BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis MN 55401-2138

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Kenneth Nickolai	Commissioner
Phyllis Reha	Commissioner
Thomas Pugh	Commissioner

IN THE MATTER OF A PETITION BY EXCELSIOR ENERGY, INC. FOR APPROVAL OF A POWER PURCHASE AGREEMENT UNDER MINN. STAT. §216b.1694, DETERMINATION OF LEAST COST TECHNOLOGY, AND ESTABLISHMENT OF A CLEAN ENERGY TECHNOLOGY MINIMUM UNDER MINN. STAT. §216b.1693

REBUTTAL TESTIMONY OF EDWARD C. BODMER ON BEHALF OF EXCELSIOR ENERGY, INC

EXCELSIOR EXHIBIT XX.0

October 10, 2006

DIRECT TESTIMONY OF
EDWARD C. BODMER

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DOCKET NO.

BEFORE THE MINESSOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF EDWARD C. BODMER

ON BEHALF OF EXCELSIOR ENERGY, INC

I. QUALIFICATIONS AND SUMMARY OF RECOMMENDATIONS

Q Please state your name and business address.

A My name is Edward C. Bodmer. My business address is 5951 Oakwood Dr. Lisle, Illinois, 60532.

Q On whose behalf are you testifying?

A I am testifying on behalf of Excelsior Energy, Inc. ("Excelsior").

Q What is your present occupation?

A I am a consultant specializing in utility regulation and energy economic analysis among other activities.

Q Who has employed you for in this assignment?

A I am working for the consulting firm Pace Global Energy Services, LLC. who in turn has been retained by Excelsior.

Q Please summarize your educational background and professional experience.

A I received a B.S. degree in Finance with highest honors from the University of Illinois in 1979 and an MBA degree with honors from the University of Chicago in 1986. My regulatory experience began with my employment on the Accounting and Finance Staff of the Illinois Commerce

Commission and has encompassed numerous assignments on regulatory issues as a consultant. In a past position as a Vice President at the First National Bank of Chicago, I managed the credit analysis of energy loans, which included evaluation of electric and gas utility company transactions and project finance deals. In that position I also directed a number of energy-related financial advice projects for bank clients.

Since 1989, I have developed a consulting practice in the electric utility industry, which has involved assignments for financial institutions, utility companies, and government agencies. My projects have addressed a variety of topics, including industry re-structuring, valuation, forecasting, pricing, resource planning, and performance evaluation. As part of my consulting business, I have presented testimony before regulatory commissions in California, Illinois, Indiana, Kansas, Michigan, Massachusetts, Maine, Minnesota, Vermont and Connecticut on a wide range of subjects. I have presented testimony on behalf of utility companies, State Commissions, municipalities, consumer groups, and taxing districts.

Another component of my practice is teaching professional development courses on valuation, project finance, credit analysis, financial modeling, and corporate finance. I have developed outlines, materials and case studies and taught courses in South America, Asia, Australia, Western Europe, Eastern Europe, the Middle East, and Africa as well as in the U.S. My work has included workshops open to the public, which I prepared for firms that arrange courses including Infocast, Euromoney, Terrapin, the Amsterdam Institute of Finance, the

Financial Training Company and the New York Institute of Finance. In addition, I have taught many customized in-house courses tailored to specific institutions. These companies have included HSBC (Hong Kong), ABN Amaro (Sao Palo), and Citibank (Tokyo), Development Bank Singapore, CIMB (Malaysia), Lindlakers (London), Saudi Aramco, the Korean Power Exchange, Indonesia Power, UAE Offsets Group, Singapore Monetary Authority and others.

Q Describe your experience with respect to resource planning and project finance?

A Much of my work over the past twenty-five years has involved economic analysis of alternative resource plans for electricity generation investments. I have evaluated the financial viability of a variety of different new capacity alternatives from the perspective of consumers, bankers and investors. I have developed techniques to measure the risk of energy investments using project finance analysis, Monte Carlo simulation and option pricing. The prior testimony referenced above includes valuation of power plants in regulatory proceedings and in property tax cases. As part of the courses mentioned above, I regularly include lectures on the valuation of capital intensive assets in a project finance context.

Q What is the purpose of your testimony?

A The purpose of this testimony is to comment on the analysis in the testimony of the Minnesota Department of Commerce presented by Dr. Eilon Amit with respect to the costs and benefits of Excelsior's Mesaba proposed

Integrated Natural Gas Combined Cycle power plant (“Mesaba”, or the “Project”). I investigate the basis of his conclusion that:

> Based on my comparable plant analysis, the cost of Excelsior's proposed IGCC plant is higher than the comparable projects and does not meet the provisions of Minn. Stat. 216B.1693 as being likely to be a least cost resource. This would mean that Xcel would not be obligated under the Statute to supply at least two percent of the electric energy provided to its retail customers from the IGCC plant. (Amit Direct testimony, page 38, line 4.)

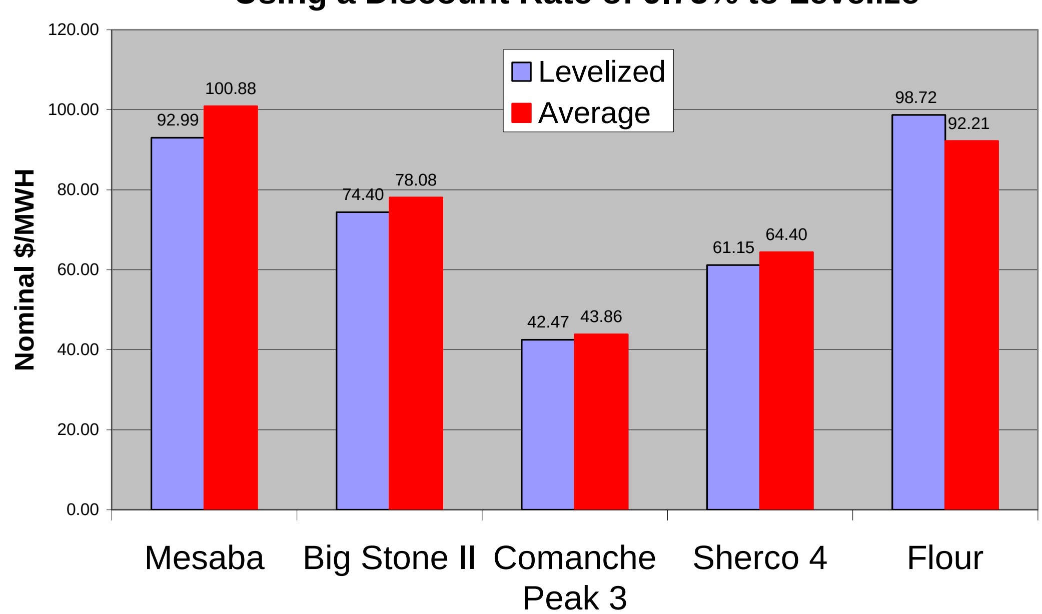
Dr. Amit’s conclusion is supported by an analysis in which Mesaba is shown to have anywhere from 28% to 118% higher ratepayer costs than alternative pulverized coal plants. The alternative coal units used by Dr. Amit are the Big Stone II supercritical coal plant that is being proposed by a number of utilities as well as two coal plants analyzed by Xcel Energy in its resource planning. The two Xcel Energy plants include the Comanche Peak 3 Unit that is being constructed by Public Service Colorado and a hypothetical pulverized coal plant at NSP’s Sherco site used as a generic addition in their modeling analysis.

Dr. Amit’s assumptions involving the cost of a coal plant are very different than the analysis presented by the Fluor Corporation and Excelsior earlier in this case. Fluor provided the costs of a new Greenfield plant that would be built in Minnesota under utility ownership, and Excelsior evaluated that plant against Mesaba PPA (“Fluor Report” and “Excelsior Cost Analysis and Comparison”).

While the Fluor Report and Excelsior Cost Analysis and Comparison apply slightly different calculation methodologies (which I will comment on later in my testimony), they both fundamentally are using discounted cash flows. However, the Fluor and Excelsior calculates total present value of cash flows, while Dr. Amit creates an annuity payment to present a levelized nominal cost. The only fundamental difference between the Fluor/Excelsior calculation and that of Dr. Amit is the discount rate. The former uses 7.95% as the discount rate, which was NSP's after tax weighted average cost of capital at the time of the analysis and Dr. Amit uses a value of 9.75% and sources a Big Stone II document.

The graph below summarizes Dr. Amit's analysis as compared to the Fluor analysis:

Cost of Mesaba and the Cost of Alternative Plants without Externalities Using a Discount Rate of 9.75% to Levelize



My testimony explains why the estimated cost of a coal plant in the Fluor scenario shown above is so different from the Big Stone, Comabnce Peak, and Sherco estimates. I also make a corrected apples-to-apples comparison of the Mesaba PPA to a supercritical coal unit in which I evaluate Mesaba against the Big Stone II plant and the hypothetical Sherco unit after adjustments for the other plants that put the numbers on an equal footing from a risk, timing, accounting and economic basis.

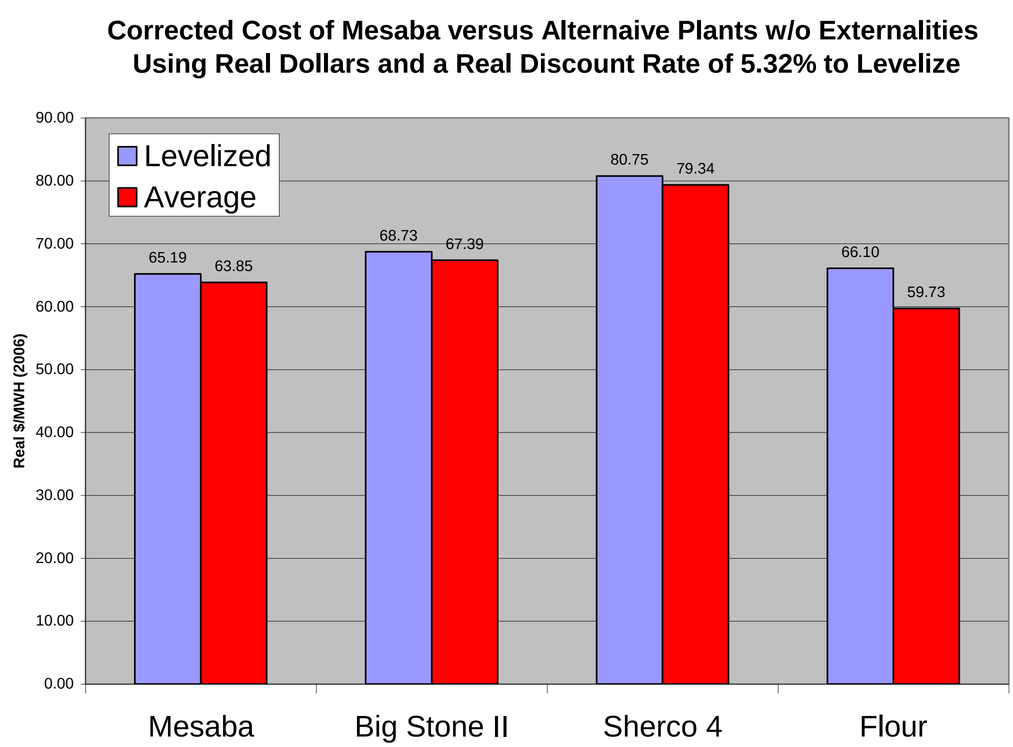
Q What is your principal conclusion regarding the testimony of Dr. Amit?

A I conclude that Dr. Amit is correct to evaluate whether Mesaba is or is likely to be a least cost alternative by considering how the project compares with other new coal plants. However, while I commend Dr. Amit for attempting to evaluate the cost of the plant on behalf of consumers in Minnesota, his results and conclusions are incorrect – to a large degree because the data he uses from Xcel and the Big Stone II economic analysis is incorrect and fails to fully account for the actual costs of those units. I note that Mr. Amit has made it clear that he is not testifying to the assumptions about costs upon which he bases his analysis; he is merely using those assumptions as the inputs that form the basis of his calculations.

The main problem with Dr. Amit's analysis is that the data he uses from Big Stone and Xcel contain different underlying analytical approaches to allocated costs in a site without an existing plant, inflation, environmental benefits, real options, first of kind costs, construction timing, and measurement of consumer risk than the prices in the Purchased Power Agreement ("PPA") used

by Excelsior. Once the allocated costs, environmental benefits, recent increases in capital cost, options, first of kind costs, and risks are put on an equal footing, my analysis demonstrates that the Mesaba plant and its IGCC technology is indeed likely to be a least cost resource for residents and businesses in the State of Minnesota.

The corrected analysis that I have developed is summarized on the graph below. I have not included the comparison with the Comanche Peak costs provided by Xcel Energy on this graph because the Comanche Peak numbers simply do not add up. My comparison uses real 2006 dollars and demonstrates the Mesaba has a lower cost of energy than Big Stone or the Xcel Energy generic unit.



The Fluor study results shown in the above graph represent a thorough and all inclusive picture of the costs of an alternative coal unit. Most importantly, the Fluor analysis uses similar assumptions – including a comprehensive set of costs - that are also fully reflected in the Mesaba PPA tariff. It is therefore close to an "apples to apples" comparison in terms of costs. In order to make it truly "apples to apples," the analysis must take into account the significant risk shifting benefits and real options offered by the Mesaba PPA over the Fluor SCPC alternative.

II. OVERVIEW AND SUMMARY OF RECOMMENDATIONS

Q Summarize the results of your analysis in which you corrected Dr. Amit's comparison of Mesaba and the Big Stone II plant.

A Dr. Amit's comparison of an expansion unit at the Big Stone site financed on the balance sheet of a utility company with the first unit Mesaba plant financed using a PPA contract is analogous to comparing apples with oranges. Correction of the Big Stone analysis in order to put it on a comparable footing with Mesaba with respect to accounting subsidies, consistent tax rates, inflation rates, start-up capacity factor and coal prices shows an appropriate first unit costs and demonstrates that the a comparable pulverized coal plant would produce power at roughly the same cost as Mesaba. The chart below shows the components of my correction before reflecting risk benefits to ratepayers, environmental benefits, real options and economic development advantages of the Mesaba plant.   In the

presentation below, I do not quantify the reduced consumer risks, increased real options and other benefits that exist for ratepayers under the Mesaba PPA.

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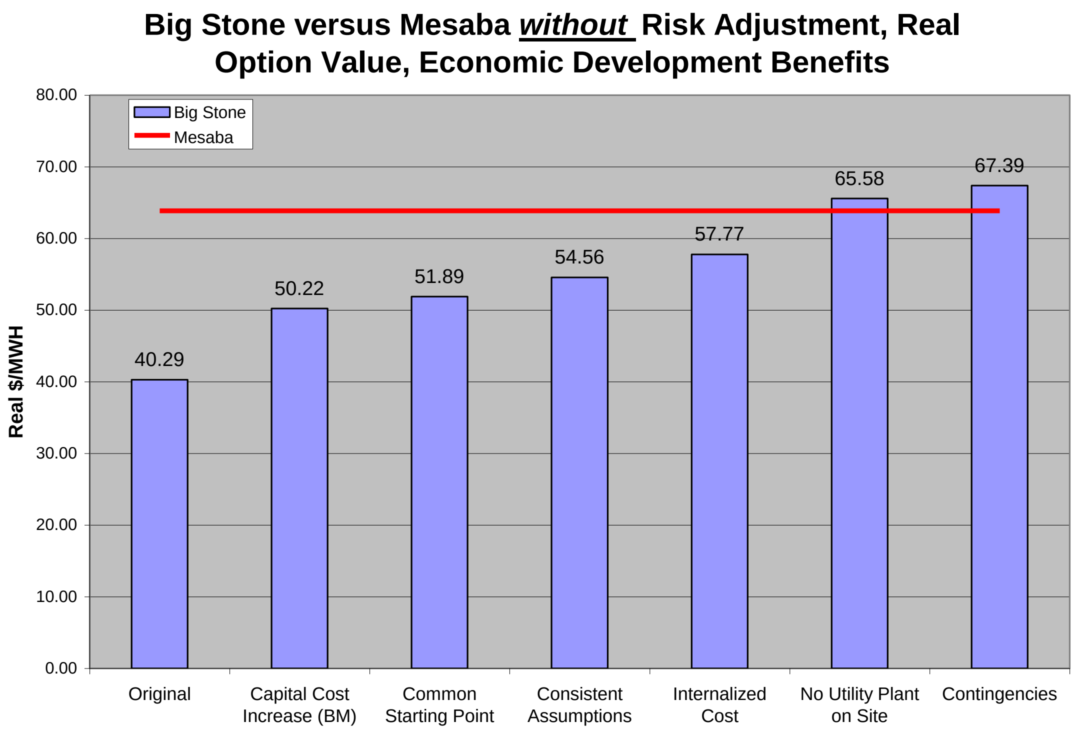
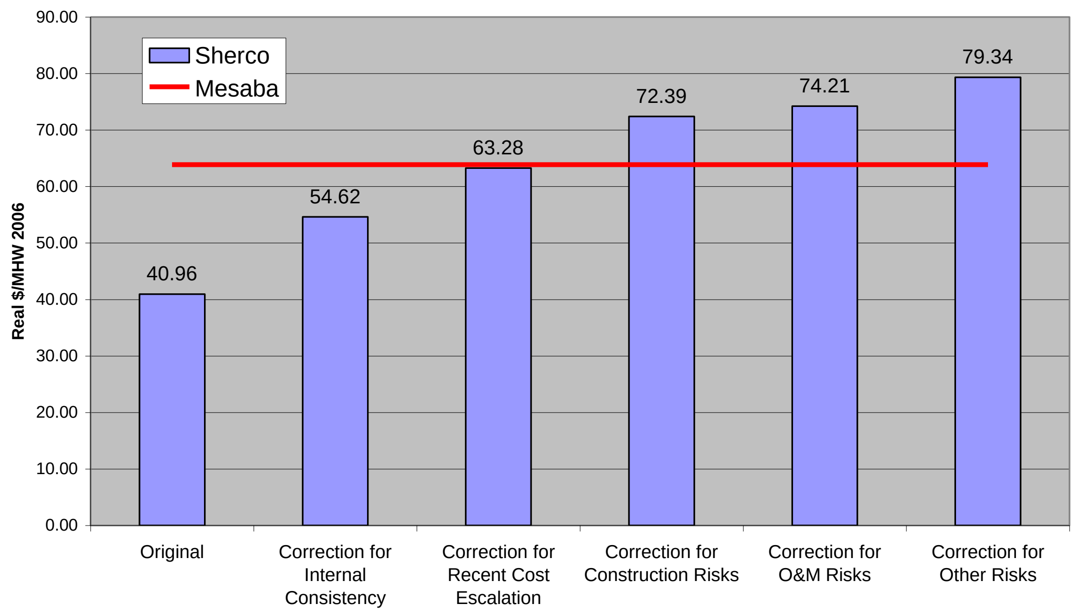


Q Summarize the results of your corrected "apples-to-apples" comparison of Mesaba with a generic supercritical pulverized coal plant at NSP's Sherco site.

A The results of my corrected analysis demonstrate that instead of Mesaba having a higher cost of energy than a new generic SCPC plant, in fact, it has a lower cost of energy. Unlike the Big Stone analysis, I quantified risk differences in evaluating the generic Sherco Unit. The graph below shows that without accounting for the environmental benefits, economic development benefits or real

option benefits relative to an SCPC plant, Mesaba has a lower rather than a higher cost to ratepayers. In addition, as with the Big Stone analysis, the Sherco analysis corrects for the recent escalation in plant costs and consistent treatment of inflation. The graph below summarizes components of this analysis.

Sherco Generic Unit versus Mesaba *with* Risk Adjustment, but *without* Real Option Value, Economic Development Benefits

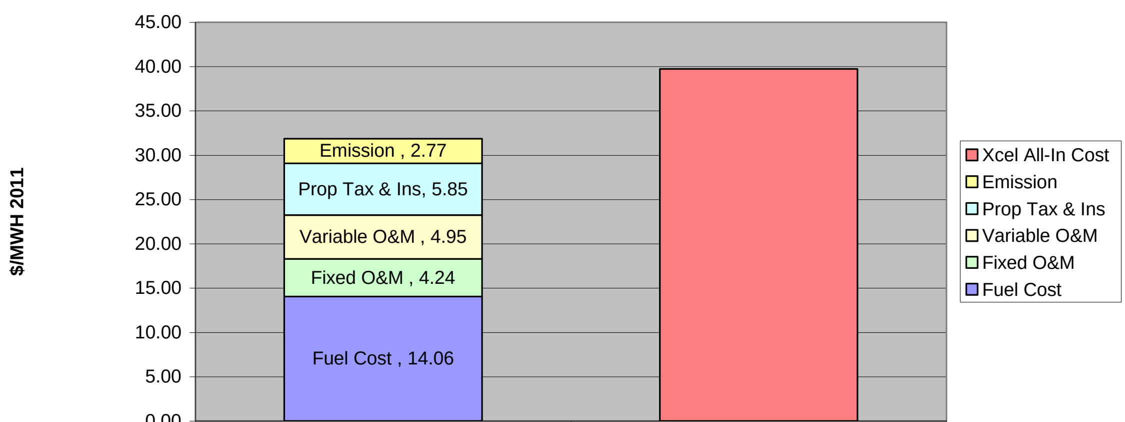


Q Summarize the results of your analysis in which you concluded that the annual cost/MWH Xcel Energy numbers that supposedly represent the cost of the Comanche Peak plant are not reasonable.

A To assess the Comanche Peak electricity cost forecast that was provided by Xcel to Dr. Amit, I have inserted the annual cost numbers shown on his exhibit into a financial model. I also input recent published cost estimates of the plant into the model along with various assumptions used in my analysis of the Big Stone plant. This demonstrates the non-transparent Xcel data omits material cost

factors for which Xcel must be receiving recovery in other areas of its corporate cost structure, because otherwise the rates paid would not come close to providing a reasonable return on the project. Xcel agrees that it is not valid to compare historical costs in Colorado to those for a Minnesota resource to be constructed in the time frame of the Mesaba Project (CITE THE INFORMATION IN AMIT'S IR). The graph below shows that the numbers provided by Xcel barely cover out-of-pocket operation and maintenance expenses and fuel costs for a coal plant. The difference between the 2011 cost provided by Xcel of $39.74/MWH and the operating cost of $31.86/MWH is nowhere near to the level required to service debt costs, equity costs and pay income taxes for the plant.

Operating Cost per MWH and Xcel All-In Cost for Comanche Peak



	Operating Cost	Xcel All-In
Xcel All-In Cost		39.74
Emission	2.77	
Prop Tax & Ins	5.85	
Variable O&M	4.95	
Fixed O&M	4.24	
Fuel Cost	14.06	

Q What are the conceptual problems with the analysis presented by Dr. Amit in which he compares the Mesaba plant with brown field plants financed on utility company balance sheets?

A Dr. Amit's attempt to compute the value of Mesaba through comparing it with alternative supercritical pulverized coal ("SCPC") units at the Big Stone site, at NSP's Sherco site and the Comanche Peak plant results in a bias against Mesaba. Because the data from Big Stone and Xcel Energy are based on fundamentally different analysis techniques and a different time frame than the numbers reflected in the proposed Mesaba PPA, the analysis made by Dr. Amit is analogous to comparing apples with oranges. I demonstrate below that the differences in analytical techniques are not trivial matters, but instead dramatically affect the measured value of capital intensive base load plants.

In the table below I list some of the ways in which Dr. Amit's cost comparisons affect the measured value to consumers of the two generating plant alternatives.

Apples to Oranges Analysis

Item	Big Stone and Xcel Energy Analysis "Apples"	Mesaba PPA "Oranges"	Implication
Construction Cost Risk	Accepted by Ratepayers and Utility Company	Allocated to Fluor and Mesaba through EPC contract from financial close forward	While cost is lower in Xcel analysis, the risk is much higher

Internalization of Operating and Capital Costs	Many costs not allocated to the plant and subsidized by other parts of the utility company	Internalizes all costs including energy management, administrative, working capital and other	Many actual costs in the Big Stone and Xcel analysis do not show up in cost/MWH of plant
First and second unit comparisons	Uses site adjacent to existing generation and does not measure the value of scarce expansion resource	Uses first unit costs that reflect the required costs to build an environmentally beneficial plant	A valid comparison must compare first unit costs to first unit costs
Operation and Maintenance Cost Risk	Accepted by Ratepayers and Utility Company	Accepted by developer and a portion is allocated to O&M contractor through O&M Contract; includes additional costs such as insurance required for project finance structure	While O&M cost may be lower in Xcel analysis, the risk is higher
Plant Availability Risk	Accepted by ratepayers and Utility Company	Allocated to Excelsior investors through PPA contract	Acceptance of availability risk by Excelsior reduces payments by Utility and Ratepayers if performance is not at targeted levels.
Timing of Construction Expenditures	Uses data before the recent run-up in construction cost	Uses up to date numbers including recent increases	The most current plant costs should be included
Risk of Changes in the Cost of Capital	Changes in the cost of capital passed to ratepayers indefinitely	Cost of capital held constant through PPA after being established at the financial close	Since the cost of capital is at low levels, ratepayers take risk of increases
Future rate of inflation and capacity factor	Big Stone analysis is based on Jan 2011 start date with 2% coal inflation	Mesaba analysis is based on October 2011 start date with 2.5% coal inflation	General macroeconomic variables must be consistent in comparing alternatives
Option to sequester carbon dioxide in the future	Very expensive carbon sequestion costs not included in the Xcel number	The option value of carboin sequestration relative to alternative plants not included in base costs	The option should be included in both analyses through evaluating the probability of sequestration
Risk premium in Cost of Capital	Does not reflect customer risk	Incorporated through risk analysis in PPA	PPA reflects most risks
First of Kind Costs	Not relevant to conventional plants	Benefits of building and financing an initial plant to subsequent units not included	Benefits to Minn economy and national energy policy should be included in the analysis

Environmental Adder Costs	Not included in analysis	Not included in analysis	Relative benefits of IGCC to Public not included

Q In evaluating whether Mesaba is a least cost resource shown in the graphs above, does the analysis in the above table include all the appropriate cost elements?

A No. When assessing whether Mesaba is a least cost alternative, additional elements must be considered including the reduced risk profile, additional environmental benefits, flexibility to meet new and tightening emission limits, real options and economic development benefits. These benefits include: A summary of these benefits includes:

1. The risk profile to ratepayers of the energy supplied under the PPA benefits ratepayers is not reflected in the Big Stone comparison. This is because with a PPA structure, rather than conventional ratemaking, consumers incur lower risks of cost of capital changes, construction cost over-runs, construction delays, operation and maintenance variation, and plant availability.
2. The Mesaba project includes a number of valuable real options that benefit ratepayers and that are not available to other coal plants. One is the option to sequester carbon; another is the option to switch between different coal sources including Petroleum Coke and a third is the option to use natural gas in providing backup capacity.
3. Additional environmental benefits accrue to citizens of Minnesota from Mesaba relative to the SCPC alternatives. These benefits are described in

Section III of Excelsior's December Filing, and include the ability to meet tightening emission limits due to the inherently lower emission profile of the IGCC technology and the flexibility of the technology to cost-effectively retrofit to meet tighter emission limits in the future.

4. Construction of Mesaba provides additional economic development benefits to citizens of Minnesota that do not occur from building conventional coal plant alternative. Construction of "first of kind" IGCC plants will allow future plants to be built at lower cost as construction techniques become more standardized. Since IGCC plants allow coal resources in the region to be used on a more environmentally friendly basis, this first of a kind premium provides value over and above the bare bones cost comparison. Second, the Mesaba plant includes employment benefits to the State of Minnesota relative to plants such as Big Stone that are built out of state or even out of the country. Third, Mesaba is being built in an economically depressed area. This contrasts to the hypothetical Sherco unit which would be built in part of the extended metro counties area.

III. TESTIMONY OUTLINE

**Q	How have you arranged the balance of your testimony?**

A After describing the organization of my testimony and an overview of contextual issues relevant to the case, the rest of my testimony describes details of the corrected apples-to-apples analysis summarized above.

Q Describe the way you have divided your remaining testimony into various sections.

A My testimony is organized as follows into eight additional sections:

1. Overview and context of risk issues associated with evaluation of resource alternatives.
2. Dr. Amit's analysis of the costs of the PPA associated with the Mesaba plant
3. Refinement of Dr. Amit's comparison of the Big Stone plant with Mesaba
5. Refinement of Dr. Amit's comparison of Mesaba with Sherco 4 and Comanche Peak 3
6. Inclusion of real options including the carbon sequestration option in the ratepayer analysis
7. PPA issues discussed by Dr. Amit

IV. ANALYSIS OF PROJECT FINANCED PLANTS VERSUS UTILITY FINANCED PLANTS—OVERVIEW AND CONTEXT

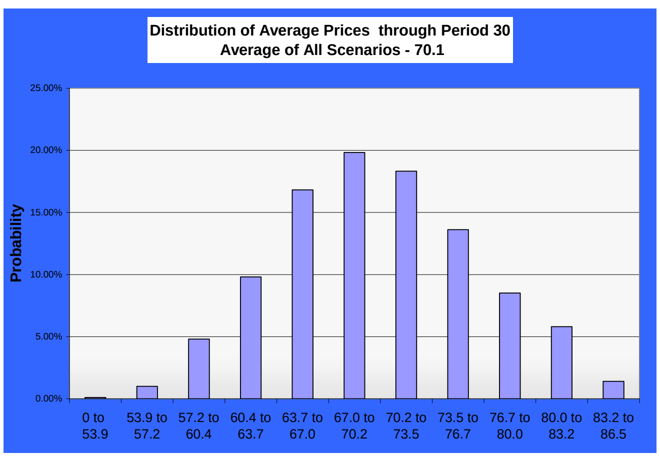
Q What issues do you discuss before you work through specific problems with Dr. Amit's analysis?

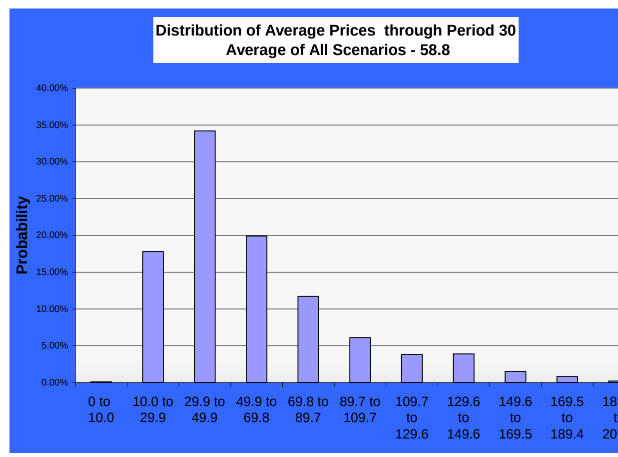
A In this section I begin by discussing general issues associated with measuring risk in the context of evaluating alternative resource additions. I include this because electricity supplied from a plant such as from Big Stone and Xcel contain very different consumer risks than the Mesaba PPA. In describing how risks affect the quantification of relative value between resource alternative, I discuss the history of capacity additions in the electric utility industry including the fact the last time the large, capital intensive plants were built – coal and nuclear plants in the 1970's and 1980's, - there were massive cost overruns, delays, prudence adjustments and utility company bankruptcies.

Q How can one define risks to ratepayers associated with different generation resources?

A Ratepayer risk associated with new generation can be defined as the variation in the cost of electricity experienced by ratepayers over the lifetime of a resource. To illustrate how risks should be incorporated in an analysis of two alternative resources, consider the following example of the evaluation of two hypothetical resources -- resource A and resource B. Assume that the base case Busbar price of a resource A is expected to be $60/MWH and it has a distribution of prices ranging from $50/MWH to $150/MWH. Resource A is more risky than a second resource -- Resource B -- which has a base case Busbar price of $70/MWH with a much smaller range of prices between $60/MWH and $80/MWH. The difference in risk is driven by uncertainty associated with construction cost, operation and maintenance cost, plant availability, heat rate,fuel prices and changes in emission limits.

To illustrate the analytical issues that arise with this problem, assume that the risks associated with Resource A and Resource B result in probability distributions shown in the graph below. I will demonstrate in my testimony below that the Mesaba plant has a far lower distribution of ratepayer prices than the Big Stone, and Sherco alternatives.





The data in the above graph do not allow a decision maker to definitively assess whether Resource A or Resource B is in fact least cost to ratepayers because policymakers must assess the value ratepayers lose from being exposed

to the higher distribution of prices versus the benefit of lower expected rates in the alternative case. This problem of explicitly accounting for different risks has been a daunting problem for policymakers. In the instant case, the analysis is simplified by the fact that IGCC need not be determined to be the single least-cost resource; by statute, it suffices if it is likely to be among the most cost effective choices. This approach, under Minnesota law, represents a more realistic, scenario-based approach to resource planning, particularly given the significant uncertainties and broad range of scenarios that must be taken into account in making resource decisions that protect ratepayers over numerous decades.

Q How can one account for the uncertainty in ratepayer when evaluating resource alternatives?

A The issue of how to quantify the ratepayer value of different risks of a resource alternative has not been resolved by academics, financial practioners or policymakers. To address the problems associated with measuring ratepayer uncertainty associated with different resource options that are illustrated in the hypothetical example above, one must be able to solve two problems. First, the probability distribution of Busbar prices must be established from mathematical equations. Second, once the probability distribution is developed, decision makers must quantify how different probability distributions affect the value of the resource.

To tackle the first part of the problem and compute the distribution of Busbar prices, one must construct mathematical equations to represent the possibility that construction costs will be greater or less than expected; that

interest rates and inflation will change; that O&M costs may not conform to target levels; that fuel costs of different plants have different volatility (i.e. natural gas prices having demonstrated high volatility in the past as compared to coal plants), that emission limits tighten, that carbon constraints are imposed and so forth. Even if we had comprehensive databases that measure the historic statistical properties of each of the risk element, the future distributions may not be representative of past data patterns.

If one could somehow create mathematical equations to represent the distribution of Busbar prices and derive a distribution analogous to the graph above, the risk quantification task would still not be solved. Indeed the second issue – translating different probability distributions of prices into value for ratepayers – is an even more complicated challenge. Sophisticated models have been suggested that incorporate volatility statistics, option pricing theory, portfolio diversification and arbitrage pricing to distributions of cash flow. While these techniques are interesting from a theoretical perspective, attempts to apply the models in practice have proven to be elusive.

Q Can project finance be used to work out risk and return tradeoffs in evaluating different resource options?

A In part, yes. Contracts in project finance enable specific risks to be quantified through allocation of the risks to various different parties. The value of individual risk elements is established through a transparent negotiation process and market based financing constraints that affect the debt raising capability of a project. For example, in the negotiation of an EPC contract to construct a plant, if

the contactor agrees to commit to a date certain fixed price contract with liquidated damages rather than a cost plus arrangement, the contractor will generally charge premium to accept the cost over-run and delay risk.[1] The riskier the construction project—arising from factors such as unconventional technology and a longer construction period—the higher the risk premium. In this example where construction risk is quantified in negotiating the EPC contract, the project finance process has established the value for a particular risk element. There is no need to estimate the distribution of construction cost over-run uncertainty and to translate the uncertainty into a value number using the theoretical techniques discussed above.

The EPC example demonstrates mistakes that can be made in comparing projects with different risk profiles. If the over-run and delay risk was not accepted by the construction contractor, the project would have a different value and different debt capacity. If cost overruns are passed through to consumers, their value is affected. Similar objective quantification of risks occur in establishing a contract for operating and maintenance expenses, establishing penalties in the PPA associated with a minimum availability factor and other provisions through a transparent negotiating process. As with the construction contract, negotiated contract terms can be used to define the value of allocating risk from one party to another.

From a ratepayer perspective, the contract that defines risk allocation is the PPA. If the PPA includes capacity payments tied to plant availability and a

[1] Liquidate damages are specific and limited amounts that a contracting party is required to pay to another contracting party in the event an agreed-upon area of performance or completion date is not achieved.

link between the initiation of capacity payments to the date commercial operation is achieved, it does not matter to ratepayers whether risks are subsequently transferred to EPC contractors such as Fluor or whether the risks are allocated to equity investors in the project. To compare the risks of a plant with a PPA (such as Mesaba) to a plant without a PPA (such as Big Stone II, Comanche Peak, or Sherco 4) where the ratepayers bear all such risks, is obviously inappropriate.

Q Are you suggesting the Mesaba plant is allocating all risks away from ratepayers?

A No. Some risks, such as the final cost estimate of the plant before financial closing and the base interest rate before financial close are carried by ratepayers during the limited period between PPA approval and financial closing. Others noted by Dr. Amit are allocated to ratepayers in the current PPA draft. My comments do not suggest that the Mesaba PPA is risk free to ratepayers. Rather, relative to a plant being constructed by a utility with development cost risk, cost over-run risk, delay risk, operation and maintenance risk, availability risk, future inflation risk, and future cost of capital risk, Mesaba does have a dramatically lower risk profile.

Q What has been the history of risks associated with capital cost in the utility industry?

A Having been involved in regulatory proceedings for many years, I realize that it is sometimes easier to confuse issues than to present an analysis that constructively helps the Commissioners in making a decision. As such it may seem that the issue of adjusting numbers presented by Big Stone and Xcel is

simply a minor skirmish between experts. To the contrary however, I demonstrate that placing alternative risks on an equal footing is perhaps the most important item in assessing the value of resources to ratepayers and that proper risk analysis can dramatically affect the valuation of new generation capacity alternatives.

The history of the utility industry over the past quarter of a century demonstrates the importance of appropriately addressing risk when considering resource alternatives. Three seminal events which had dramatic negative consequences for consumers include (1) the cost escalation of nuclear plants in the 1970's and 1980's; (2) the California power crisis in 2000-2001; and (3) the recent escalation in natural gas and oil prices that has produced rate increases greater than 50% for customers in many areas of the country. Each of these events which had negative consequences to ratepayers was driven in part by failure of investors, utility companies and policymakers to assess the risks inherent in a resource strategy.

Q How did problems associated with constructing nuclear plants illustrate the importance of risk allocation in construction contracts?

A Many nuclear plants and to a lesser extent coal plants experienced dramatic cost over-runs in the 1970's and 1980's because the volatility of construction expenditures was very high. While the reason for these cost increases—regulatory changes, non-standard technology or management imprudence—is still subject to debate, there is no doubt that the uncertainty in construction costs and construction length was very high. In the 1970's nuclear

plants were generally estimated to cost $1,000 per kW or less, while the actual cost was often more than $4,000 per kW. The cost over-runs came along with long delays in the construction of the plants. The dramatic cost over-runs experienced by nuclear plants caused massive dislocation in the industry with implications ranging from the bankruptcy of Public Service of New Hampshire to movement to deregulate the industry.

Were the construction cost over-run risk associated with nuclear plants to have been allocated to contractors and/or private developers who could not pass-on costs to ratepayers, I suggest the utility industry would look very different today. If the parties constructing the nuclear plants had been allocated the risk of cost-over-runs through a transparent negotiating process with construction contractors and an EPC contract, the initial plant cost estimates would not have been low balled and the decision making process would have been much better. In the case of nuclear plants—long-lead time investments using unconventional technology—the risk allocation of construction costs was a crucially important issue.

Q With hindsight, would the allocation of operating risks away from ratepayers to private developers have had similar implications as the construction issue?

A Yes. Had the utility industry objectively measured risks associated with plant availability, heat rate variation and unexpected movements in operation and maintenance expenses, investment decisions may have been different. Problems with nuclear plant availability and with operation and maintenance expense increases caused severe financial distress for some utility companies and resulted

in rate uncertainty for consumers. On the other hand, plants constructed by private developers have protected customers from technical and operation and maintenance risk. An example of the costs and benefits of risk allocation is the Alstrom combined cycle plants such as the Lake Road facility built in New England. Technical problems with these plants resulted in a much worse heat rate and much higher operating and maintenance expenses than had originally been anticipated. Rather than these problems causing rates to go up, Alstrom was forced to compensate the owners of the plant with large liquidated damage payments. Had a contract with liquidated damages not been signed, the financing may not have been arranged and the plant may not have been built. Here, the higher costs that were incurred for liquidated damages quantified a particular risk element. Utility owned plants don't pay premiums in contracts for liquidated damages, but they also don't mitigate risks.

Q Does the lack of risk quantification for utility owned plants cause a bias in resource planning?

A Yes. I am old enough to remember the certificate of need cases for utility plants that were build many years ago. In those cases as in the integrated planning cases of today, utility companies had an incentive to low ball the cost of their preferred resource. If the true costs of a utility plant including the risks of construction cost over-runs and operating performance are internalized – by being explicitly fixed and allocated to the utility in the regulatory proceeding - rather than just being passed along to ratepayers as they are incurred after regulatory approvals, all costs would be forced into the open, examined. The process would

then present a more meaningful basis to determine which resources are truly least cost.

In the resource planning processes, utilities have an incentive to underestimate the true costs of self-build plants. For example, Xcel uses "generic" capital costs estimates that do not include specific costs for real plants and Big Stone makes optimistic operating and maintenance projections. Utilities are not held to the generic estimates made during resource planning as is the case for independent developers. Furthermore, in many cases, rate based costs throughout the company that are increased because of the construction of a new plant (development costs, overhead, inventory carrying costs, engineering, etc.) are never considered in the "evaluation" in an IRP setting.

In contrast, an independent developer must identify and fund all development costs, capital costs, and all operation and maintenance costs; and thus, they must identify all of them and recover them through the tariff. You cannot play a shell game in project financing.

Q Are the problems by the second seminal event—increases in wholesale prices experienced in California—germane to the assessment of capacity expansion alternatives in this case?

A Yes. People who have studied the issue have suggested many different reasons for the dramatic increases in wholesale prices in California in 2000-2001 that resulted among other things in the bankruptcy of Pacific Gas and Electric and cessation of the deregulation movement around the world. One often-cited reason for the California crisis is the lack of long-term contracts signed by the tree large

distribution companies. Before the crisis, it may have seemed that long-term contracts that included capacity charges were too expensive and it was better to not fix the cost of electricity for a portion of the electric energy requirements. With hindsight however, the premiums that would have been required to pay for contracts to provide price certainty would have been enormously beneficial to the state. Reluctance to sign contracts that involve capacity payments because they seem expensive is understandable, but the California case clearly demonstrates that the added cost of fixed prices -- when compared to the risks averted by hedging -- can be a very valuable proposition.

Q Are current experiences in the Northeast and elsewhere in the country with respect to exposure to volatile natural gas prices problems pertinent to analytical issues in this case?

A Yes. For most people working on resource planning in the past twenty years, it has seemed clear that the only type of resource that should be added was a natural gas combined cycle plant or a natural gas combustion turbine facility. However in the past couple of years, dramatic and largely unforeseen increases in natural gas prices have demonstrated that risks of a fuel cost-intensive plant must be included in analysis of a coal versus gas plant. In the past, the capital costs of coal plants appeared too expensive. However recent price increases have made it clear that accepting and paying for capital costs that result in lower fuel price would have been a good policy decision. In sum, capacity charges may seem high, but they buy protection from fuel price fluctuations. It is important to bear

in mind that utility forecasts of natural gas prices are not, in fact, hedges of those prices in reality.

IV. DR. AMIT'S QUANTIFICATION OF MESABA'S COST

Q Summarize the analytical approach used by Dr. Amit to quantify the ratepayer costs from the Mesaba plant relative to an alternative coal unit.

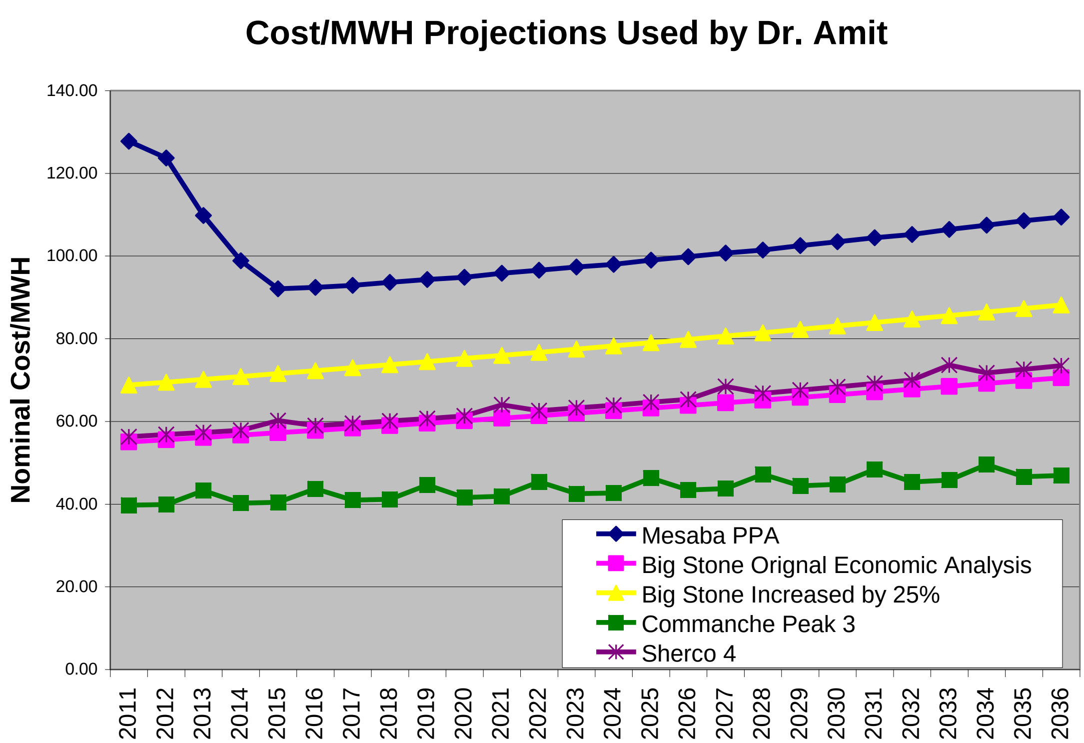
A Dr. Amit uses data from various different sources to assess the costs to consumers from the Mesaba plant as compared to an alternative coal plant. For example, he states:

> These prices [of Mesaba] must be compared to the prices of alternative Baseload facilities of similar sizes. If the prices of the PPA are lower or similar to the prices of energy and capacity of the alternative Baseload facilities, we can conclude that the PPA's prices are reasonable. (Amit testimony at page 28.)

The idea of seeking cost data from different sources and comparing the prices in the Mesaba PPA is commendable. Unfortunately, there is no objective "check" on this data that can be performed, since the utilities are not bound by the estimates they provide in the certificate of need forum.. This makes the cost estimate performed by Fluor, who is a national leader in the construction of coal facilities, more useful to the Commission's analysis than the utility estimates. Fluor is in the marketplace offering a SCPC product, and has direct, real-time access to the cost factors that influence construction costs and operating costs. The analysis they provide is explicit and clear, and subject to ready scrutiny by the other parties in this docket. Fluor's interest in being selected to bid on coal

facilities throughout the country makes its cost estimating credible. In contrast, the Big Stone and Xcel data is incomplete, and not supported by testimony or witnesses in this docket. Further, the Big Stone and Xcel analyses are subject to an inherent bias towards self build proposals. After closely scrutinizing the information supplied by Big Stone and Xcel to Dr. Amit, it is clear that the data cannot be used to make a valid analysis of the ratepayer costs for the Mesaba project as compared with an alternative SCPC unit.

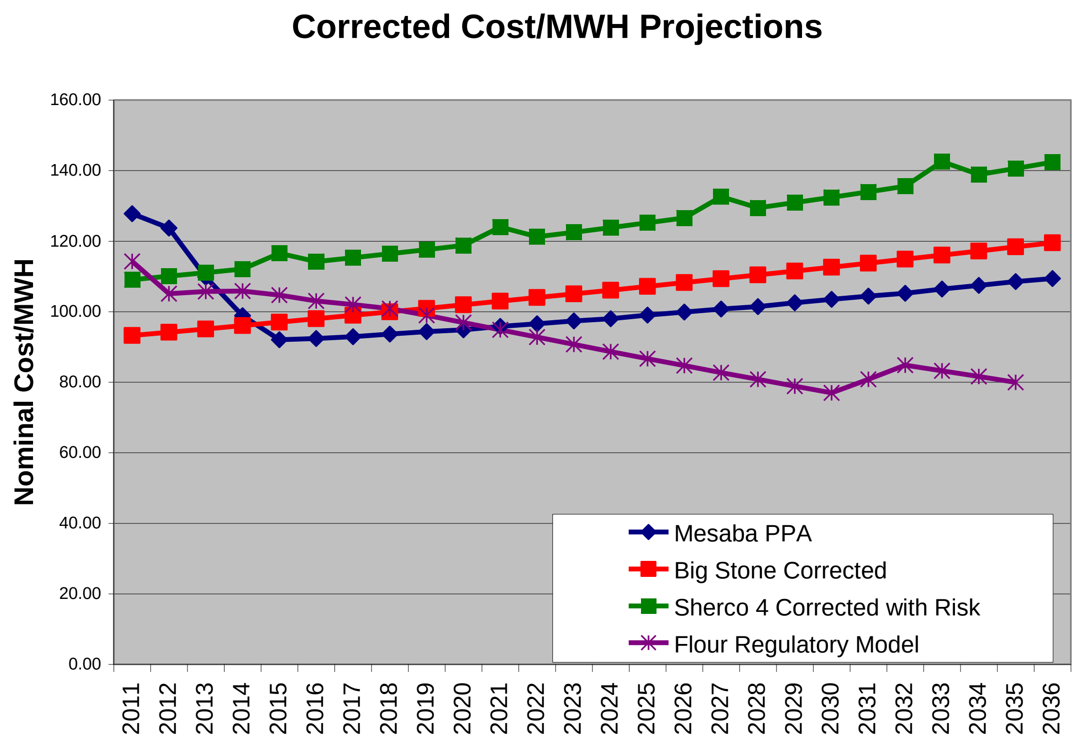
The cost per MWH information for the various plants used by Dr. Amit are illustrated in the graph below. The graph demonstrates the Mesaba PPA prices are higher than the data supplied to the Department for the other alternative, and that the Mesaba prices have a declining pattern in the initial few years.



While the data appear to be consistent across time frames, the time period for the Mesaba plant is in fact different than the other alternatives because Mesaba begins operation October 2011 while the other alternatives are assumed to begin operation at the beginning of 2011. The data provided to Dr. Amit by the utilities for the comparable coal plants do not have underlying documentation as to the level of capital and operating costs, the heat rate, the cost of capital and other parameters.

Q After correcting the cost assumptions embedded in Dr. Amit's analysis, what happens to the nominal costs shown in the graph above?

A In analyzing the Big Stone, Sherco and Comanche Peak data, I have found that a fair comparison of the alternatives produces a very different pattern. In the modified analysis, I have removed the Comanche Peak estimated cost because the numbers do not add up and cannot under any methodology be logically tied to the published cost estimates of the plant. I have also eliminated the original Big Stone numbers because they are irrelevant given the current cost estimates. This leaves four lines – the Mesaba tariff, the corrected Big Stone analysis, the Fluor analysis and a new Sherco unit, for which Xcel provided the cost assumptions.



Q Do you concur with Dr. Amit's general approach to determining whether Mesaba is or is likely to be a least cost alternative through comparing Mesaba's cost to other coal plants?

A Yes. The degree to which a base load alternative is a least cost resource should be evaluated through comparing different base load resources on an apples to apples basis. Much of the cost of a base load plant is comprised of the capital cost and the non-fuel operation and maintenance cost. Further, the new base load plants, being more efficient than existing plants, are among the first plants to dispatch on a system. Through directly evaluating the overall cost of alternative base load resources, an analysis which directly compares two plants appropriately focuses on the important cost elements – which are readily understandable and susceptible to a real debate - rather than comparing costs after two units with

similar dispatch have been run through a system model that cannot be understood and debated.. Since a number of utilities (NSP, PS Colorado and utilities participating in the Big Stone plant) have proposed new coal fired plants to meet base load needs, the comparison of the Mesaba to other coal plants is appropriate. Further, as demonstrated by debates that are occurring in this case, it is complex enough to assess the economics of a coal plant compared to another coal plant without having to assess natural gas price risk, the value of baseload versus non baseload and other issues.

Q Describe the process of using the present value of revenue requirements ("PVRR") to compare resource alternatives?

A The present value of revenue requirement approach has long been used in comparing resource alternatives in the utility industry. The method is of limited use, and should be significantly adjusted in comparing alternatives that have different ratepayer risks. In looking at it from the ratepayers' perspective, the approach is the inverse of normal capital budgeting, so that a lower discount rate should be applied to the riskier supply and a higher discount rate should be applied to the more secure supply.

Such an adjustment to methodology would strongly favor the Mesaba PPA over a utility rate based alternative. I do not, however, make a risk adjustment in the analysis below which would favor the Mesaba plant.

Q What discount rate did you use in levelizing ratepayer costs?

A While I believe the many of the traditional approaches used by utility companies are theoretically incorrect, I have used standard approaches in

measuring the levelized cost of Mesaba relative to alternative plants. From a ratepayer perspective revenues are pre-tax numbers that should be discounted at pre-tax discount rates. Further, as demonstrated by my discussion above, risk premiums applied to ratepayer costs should be subtracted instead of added to discount rates. For purposes of this analysis, I have not attempted to reflect this reality, and for purposes of simplifying the anlaysis, have used the utility company discount rate. I understand that in Minnesota the typical method is to use the utility company after tax weighted average cost of capital – which was 7.95% (and will be 7.41% under the new rate case order.) To limit debate on this issue, I have used 7.95% in my analysis

In presenting alternative, Dr. Amit uses nominal cost/MWH numbers. While this approach does not necessarily bias the relative cost of Mesaba and alternative plants, it does distort the presentation. The computation of average nominal cost means that a cost in 2011 is compared with a cost that occurs 25 years. It also means that the costs cannot be put in a relevant context relative to current costs. I therefore present costs in real 2006 dollars as well as in nominal dollars.

IV. DR. AMIT'S ANALYSIS OF THE MESABA PPA COSTS VERSUS INVESTOR OWNED FINANCING OF THE BIG STONE II PLANT

Q What source did Dr. Amit use as the basis for his comparison of the cost of Mesaba with the second unit at the Big Stone site?

A Dr. Amit began with a series of numbers presented in Section 5 of the report titled “Analysis of Baseload Generation Alternatives” which was published in September 2005. The data was taken from a table titled: “Table 5-3: Annual Busbar Costs ($/MWH).” The row of numbers from 2011 to 2030 titled “Investor Owned Utility: Super PC” contains the same numbers that are titled “Supercritical $/MWH” in Exhibit DOC – EA-4. For the years from 2031 though 2036, Dr. Amit escalates the $/MWH cost by 1% per year.

Q How does Dr. Amit refer to the data taken from the 2005 Big Stone Analysis?

A Dr. Amit implies that the Big Stone analysis is comparable to the Mesaba PPA as demonstrated by the following statement in his testimony:

> The price of the supercritical coal plant in the Big Stone proceeding is based on the period 2011 through 2030. To compare it to the price of Excelsior Energy over the same time period, I used the average annual price increase of the supercritical plant over the period 2011-2030 to estimate its annual prices for the period 2031-2036. (Amit testimony page 22, line 1)

Q Do the Big Stone costs used by Dr. Amit use similar financing assumptions that underlie the Mesaba PPA?

A No. While a quick read of Dr. Amit’s testimony gave me the impression that the Big Stone analysis is comparable to the Mesaba plant with a PPA, the financing approach is very different. The source report Dr. Amit used to derive his number notes that:

> Of the seven participating utilities, OTPCo and MDU are investor owned utilities. CMMPA, GRE, MRES, HCPD and SMMPA are public power utilities. Note that each of the seven participating utilities will have its own financing plan, capital structure, rate of return, tax rate, and depreciation schedule for its share of the BRIT Project, and the specific cost of capital assumptions will vary. (Analysis of Base Load Alternatives, page 5-5).

There is nothing in the Big Stone 2005 report that mentions a purchased power agreement or project finance. This means Dr. Amit is comparing the Mesaba plant that has risk allocation, internalization of costs and other items derived on pricing in a PPA with a brown field project in which costs are measured with generic utility financing.

Q What are some cost and risk items that are not incorporated in the Big Stone analysis by virtue of not basing the analysis on a fully negotiated PPA?

A There are elements that make the Big Stone numbers not comparable to the Mesaba PPA. These include:

- The starting point of the Big Stone analysis is different than the Mesaba PPA numbers and the cumulative inflation assumptions from 2006 to 2011 are not consistent.
- The Mesaba numbers use an assumption that the plant will not operate at its maximum performance in initial years of operation; the same assumption is not made for Big Stone, although there is not significant evidence to indicate that an SCPC coal plant will meet its target

performance in its first years of operation (see the testimony of Ron Wolk).

- General economic assumptions including the income tax rate, the coal inflation rate and the base coal price are different between the Big Stone analysis and the Mesaba PPA projections.
- Various costs that are included in the Mesaba PPA are not internalized in the Big Stone study but are instead allocated to the utility balance sheet of the utility administrative and general expenses – thereby understating the true costs to ratepayers of the plant.
- The Mesaba PPA is derived from the costs it experiences in developing the first unit on a site while the Big Stone unit is derived from an analysis that includes savings from being an expansion unit.
- The Big Stone analysis does not incorporate assurance of operating and maintenance expenses or availability guarantees that are part of the Mesaba PPA.

Q What do you mean by the statement that many costs are not internalized in the Big Stone study?

A Many costs are allocated differently for a first unit plant such as Mesaba that is financed with a PPA than an expansion plant that is build at an existing site and financed on the balance sheet of an investor owned utility company. The fact that costs are not included in a study does not mean that the costs do not exist; they are simply accounted for in the general and administrative costs of the utility and will ultimately be recovered from the ratepayers. A simple example is the

work that is submitted for this proceeding and the work that Big Stone presented. While Mesaba must include all of the development, engineering, legal and consulting and other costs in the quoted tariff under the PPA, the utilities constructing the Big Stone plant will include the costs in general and administrative expenses. Other similar costs that are not internalized include working capital, energy management costs, general management costs, general insurance, business interruption costs and other items.

Q Why is it not appropriate to compare the Mesaba plant's first unit with an expansion unit such as Big Stone II?

A Since the Big Stone plant is an expansion unit, the plant benefits from shared costs that are not available to the first unit on a site that will obviously bias the analysis against the initial unit. The cost advantages of a second unit are cited often in documents prepared by Big Stone. For example, the 2005 Big Stone analysis noted:

> The additional staffing required for the PC units was estimated and added to the existing Big Stone Unit I staff. Half of the total staff from both units was included in the O&M cost estimates for Big Stone Unit II. This results in 52 staff members attributed to Unit II. (Big Stone Study 3-2)

Q Why should Big Stone savings that exist because it is an expansion plant be removed from the Mesaba comparison?

A The appropriate comparison for Mesaba must be a first unit to first unit analysis because:

- If expansion units were used as the standard against which all other resources are measured, no new environmentally beneficial resources would be added in Minnesota.
- Expansion sites are a scarce resource with significant value. However, the type of analysis prepared by Big Stone and Xcel attributes no transfer costs for the use of the expansion site. Opportunity costs should be included in any analysis.
- Taken to the extreme, the comparison of expansion sites to first units would lead to every new plant being built at one site – ultimately there could be twenty plants at Big Stone and fifteen plants at Sherco. Limits on land availability and diseconomies of scale dictate that this of course will not happen.
- The Mesaba site is planned to be large enough for two units. In theory, the value of the real option to build a second unit should be attributed to Mesaba.

Q What are the financial assumptions that underlie the numbers presented in the Big Stone analysis?

A The financial assumptions include the following:

Interest Rate	7%	
Term	20	
Debt/Equity Percentage	50/50	
Return on Equity	12%	
Construction Financing Fees	0.50%	
Permanent Financing Fees	1.0%	
Construction Financing	48	Months
Discount Rate (Investor Owned Utility)	9.75%	
Discount Rate (Public Power)	6.00%	
Effective Tax Rate (IOU only)	40.00%	
Book Depreciation	30 years	
Tax Depreciation (IOU only)	20 years	

I have used these assumptions along with operating assumptions documented in the Big Stone analysis to "reverse engineer" the analysis. Through this benchmarking process, I am able to then analyze alternative assumptions such as the increased capital cost and increased fuel cost of the unit in a more precise manner than Dr. Amit's 25% adjustment.

Q Explain how you have used the Big Stone data to reverse engineer the Big Stone analysis and derive the original stream of cost per MWH numbers that Dr. Amit extracted from the Big Stone report?

A I have created a financial model of the Big Stone plant using the original data filed by Burns and McDonald. When I entered the data the rate of return earned on equity was 11.95% — very close to the 12% ROE assumed in the study. The project finance model is included in my work papers with formulas in tact. This replication process is important because it allows me to evaluate changed cost, economic and technical parameters on an incremental basis and assure that the effects of the change are not influenced by a different starting point.

Q Once you replicated the Big Stone model, what alternative scenarios did you develop to model the costs of a project financed plant?

A The alternative cases include:

- A case that corrects for the updated plant cost and updated cost data based on information recently filed by Big Stone.
- A case that includes the above updated cost and corrects for inflation through 2011 and corrects for the different starting points.
- A case that includes the above and incorporates the same prospective coal prices and coal price inflation.
- A case that includes the above and includes the following adjustments to reflect internalized costs.
- A case that includes the above and incorporates Fluor O&M cost estimates to reflect the cost of a first unit versus an expansion unit site.
- A case that includes the capital cost estimates used by Fluor to demonstrate other EPC costs associated with liquidated damages.

Q Did you adjust the capital cost to reflect required costs contractors require to build a plant with a fixed price date certain contract rather than a cost plus arrangement?

A No. While the transfer of construction cost risk in project financing adds to the capital cost of a facility, I have not revised the Big Stone numbers for this factor in the adjusted scenarios. I did not make an adjustment for transfer of construction cost over-run risk because the Big Stone analysis mentions an EPC contract. If the Big Stone EPC contract does not have a fixed price and a required completion date with liquidated damages that transfers risk away from ratepayers, the Big Stone capital cost should be increased to reflect that this risk is borne by ratepayers. The Fluor analysis correctly accounts for utility financing including

constant capital structure, declining revenue requirements patterns and AFUDC. I note a key benefit of the Mesaba plant is its highly efficient financing from low interest rates, investment tax credits and high leverage.

Q Do you agree with the approach that Burns and McDonald used to convert capital costs into required revenues in their analysis?

A No. By assuming that the Big Stone plant pays off debt over 20 years, Burns and McDonald are assuming changing proportions of debt and equity over the life of the plant. The Burns and McDonald approach is a hybrid between an IPP financing approach and a classic utility financing method that understates the true costs to ratepayers. A traditional utility analysis would assume that debt and equity are paid off in equal proportions over the life of the plant which maintains a constant capital structure.

I have evaluated the effect of different financing approaches on the pre-tax carrying charge rate paid by ratepayers. This analysis shows that the Burns and McDonald approach results in a pre-tax carrying charge rate of 12.36% while the traditional utility approach would result in a carrying charge rate of 13.04%. Thus, the financing assumption made by Burns and McDonald understate the cost of the Big Stone plant to ratepayers.

Q What is the source of the data you used to reflect the increased cost that were announced by Big Stone?

A Because the Big Stone unit does not have a PPA that defines capacity charges, estimated cost data and performance data is derived from estimates rather than from committed contracts. This is demonstrated by the recent filing of utility

companies that are part of the consortium. Many of the assumptions made by different utility companies were not at all consistent. For example, a study by Burns and McDonald presents the updated cost per kW as $2,168 in 2012 dollars while the PA consulting study prepared on behalf of MDU presents the 2006 $/kW as $2,461. A recent press release estimates the plant cost to be $1.6 billion for 630 MW that amounts to a per kW cost of $2,539/kW. In terms of fixed operation and maintenance expense, the PA study presents a value of $27.70/kW/year while the Burns and McDonald study presents a cost of less than half of the number -- $10.11/kW/year. There even seem to be differences with respect to the capacity of the plant and the issue of whether the plant rated 600 MW or 630 MW during normal periods. The Burns and McDonald study uses a capacity increase while the PA study does not. The difference between the two analyses is shown on the two tables below:

Changes in New Resource Cost Assumptions

PROJECT TYPE	630 MW PC Supercritical Big Stone Unit II	500 MW Combined Cycle Greenfield	500 MW Combined Cycle + Wind [1]
Number of Gas Turbines	N/A	2	2
Number of Boilers/HRSGs	1	2	2
Number of Steam Turbines	1	1	1
Steam Cycle Type	Supercritical	Subcritical	Subcritical
Design Fuel	100% PRB	100% Natural Gas	100% Natural Gas
NOx Control	Low NOx Burners, SCR, OFA	Dry Low NOx Burners, SCR	Dry Low NOx Burners, SCR
SO2 Control	Wet Scrubber	N/A	N/A
Particulate Control	Baghouse	N/A	N/A
Ash Disposal	Landfill On Site	N/A	N/A
Net Plant Output, kW	630,000	500,000	500,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,095	6,704	7,204
Capital Cost, $/kW (2012 COD) [2], [3]	$2,168	$749	$749
Fixed O&M Cost, $/kW-Yr (2006$) [4]	$10.11	$7.81	$7.81
Variable O&M Cost, $/MWh (2006$)	$2.23	$3.85	$3.85
Purchase Price of Wind (2012$)	N/A	N/A	$60.00

PROJECT TYPE	630 MW PC Supercritical Big Stone Unit II	500 MW Combined Cycle Greenfield	500 MW Combined Cycle + Wind [1]
NOx, lb/MMBtu	0.07	0.011	0.011
SO2, lb/MMBtu	0.10	< 0.0051	< 0.0051
CO2, lb/MMBtu	208	110	110
Hg, lb/MWh	$2.1\text{^}10^{-5}$	N/A	N/A

[1] Cost, performance, and emissions for CCGT component, assumed to operate at 48% capacity factor.
Non-firm wind energy assumed to be purchased at $60/MWh at equivalent energy to displace 40% CCGT capacity factor.
[2] Capital costs for BSII estimated as $1.366 billion for 630 MW net by Black & Veatch.
[3] Capital costs for CCGT based on B&V Study, $562/kW plus 20% Owner's Costs (2006$).
Escalated conservatively at 2.5% annually.
[4] Fixed O&M costs for BSII do not include property taxes and insurance, added subsequently in pro forma.

Changes in New Resource Cost Assumptions

New Resource Cost Assumptions: July 13, 2006 Report

Unit	Fuel	Capacity (MW)	Full Load Heat Rate (Bt/kWh)	Capital Cost $/kW (2006)	Fixed Cost $/kW (2006)	Variable Cost $/MWH 2006
Combustion Turbine	Natural Gas	43	8,900	616	6.35	6.04
Combined Cycle	Natural Gas	120	7,200	921	26.48	2.44
Bigstone II	Coal	116	9,600	1,645	14.36	2.98
Wind	Wind	50		1,500		4.60
IGCC	Coal	116	9,612	1,821	24.15	6.06
LV-21	Coal	116	10,440	2,745	46.72	2.75

New Resource Cost Assumptions: September 2006 Update

Unit	Fuel	Capacity (MW)	Full Load Heat Rate (Bt/kWh)	Capital Cost $/kW (2006)	Fixed Cost $/kW (2006)	Variable Cost $/MWH 2006
Combustion Turbine1	Natural Gas	43	9,000	916	32.22	3.67
Combined Cycle1	Natural Gas	130	7,550	1,668	18.85	3.73
Bigstone II1	Coal	116	9,600	2,461	27.70	1.70
Wind	Wind	50		1,500	25.00	4.60
IGCC	Coal	116	9,612	2,668	24.15	6.06
LV-21	Coal	116	10,440	2,745	46.72	2.75

Q Why does the type of cost uncertainty shown in the above tables not exist for the Mesaba plant?

A The capital and fixed O&M costs for the Mesaba plant are fixed in advance through capacity charges in the PPA contract. Unlike the case of utility financed plants it is not possible to "bait and switch" or "low ball" the estimates in order to

justify a plant with incomplete costs, and then ultimately recover more than was forecasted from ratepayers.

Q How have you modeled the effect of the cost estimates presented by Burns and McDonald and PA Consulting?

A In the case of the PA consulting estimates, I have used data from their table and escalated the 2006 dollars to 2011 dollars. In the case of the Burns and McDonald numbers, I used their assumptions along with the cost of the plant published in the press release. (I did not use the cost estimate in the table because it does not include all interconnection costs.) After entering the difference costs, I derived first year price that generates the target rate of return of 12% used in the original numbers extracted by Dr. Amit. When the PA numbers applied in the benchmarked model, the real cost/MWH of Big Stone is $56.47/MWH – about 12% below the $63.85/MWH Mesaba PPA cost. On the other hand, the real cost/MWH using the Burns and McDonald study is $50.22/MWH.

Q What numbers have you used to represent the recent announced cost increases of Big Stone?

A I have used the Burns and McDonald numbers as a simplifying and conservative assumption to be used for purposes of this analysis. However, since there is such large difference in the heat rate assumption between the analyses I have used the Fluor Heat Rate of 9,450 BTU/kWh.

Q Describe the adjustment you made to use a comparable time frame in the analysis.

A The commercial operation date for the Mesaba plant is October, 2011 while the starting point for the Big Stone II plant is January 2011. Since nominal dollars are being evaluated, the mixing of start dates creates a minor bias against the Mesaba plant. To illustrate this, consider a much more extreme example where a plant constructed in 1980 is compared to a plant that begins operation in 2011. If nominal dollar per MWH numbers are being used to compare the two plants, the plant that starts in 2011 will of course look more expensive than the plant that begins operation in 1980.

To correct the starting point problem, I have increased the Big Stone capital and operating cost by a factor that represents an annual inflation rate of 2.5% that over a nine month period.

Q How have you adjusted for initial lower capacity factor?

A In constructing the PPA assumptions, Excelsior assumes that the plant will not immediately operate at its ideal capacity factor. The benchmark of Big Stone costs assumes that it can immediately achieve an 88% capacity factor. I have modified the Big Stone scenarios to correct this inconsistency through assuming an 80% capacity factor for the first two years of operation.

Q Describe the adjustment you made to use consistent inflation, fuel price and income tax assumptions.

A It is important that a comparison between alternatives is not biased by different macro economic assumptions. If one plant is evaluated with high inflation and high fuel prices while another is evaluated with low inflation and prices, the analyses will obviously not be comparable.

To correct the problem of consistent assumptions I have applied assumptions that underlie the PPA price analysis to Big Stone. The corrected assumptions include the 43% income tax rate used in the Mesaba model, a 2.5% coal price inflation rather than either the 2% coal price inflation used in the original Burns and McDonald study. In addition, the initial coal price in 2011 must be consistent. The Mesaba energy charge is derived from an assumption of a mix of petroleum coke and PRB coal while the Big Stone plant uses only PRB coal. The coal price for the PRB portion of the Mesaba coal use is $1.39/MMBTU in 2011.

Once consistent assumptions are included, the average real cost for Big Stone is $54.56 relative to the Mesaba real cost of $63.85.

Q What adjustments have you made to reflect internalization of costs?

A In order to model the effects of the manner in which utility companies record costs in accounts external to the plant, I have made the following adjustments:

- The O&M cost is increased by 10% to reflect administrative costs that will be incurred at the utility level;
- Working capital requirements are included in the model.

Q Describe the adjustment you made to remove the distortions created by comparing a first unit site with an expansion site.

A To simulate Big Stone costs exclusive of site synergies, I have made the following adjustments.

- I have increased the capital cost by $203/kW in order to reflect the common costs of items such as land, and transportation discussed above. This number is based on the analysis made by Fluor of OSBL (outside the battery limits) costs.

- I have used the fixed O&M and the variable O&M per MWH in the Fluor study of a new first unit.

Q How have you modeled additional capital cost contingencies that may arise before the plant is completed?

A In testimony recently filed, owners and consultants to the Big Stone project acknowledged that there may be added cost changes to the plant. To model these contingencies I have used the Fluor capital cost assumptions. The table below summarizes all of the adjustments.

	Original Big Stone Analysis	Revised Big Stone - PA	Revised Big Stone - BM	Common Start Point	Consistent Fuel and Tax	Internalized Cost	Green Field	Contenginces
Capacity (MW)	600	630	630	630	630	630	630	630
Capital Cost ($/kW) - Total	1,800	2,784	2,539	2,592	2,592	2,592	2,795	2,989
Capital Cost ($/kW) without IDC	1,641	2,417	2,204	2,250	2,250	2,272	2,426	2,620
Heat Rate	9,369	9,600	9,450	9,450	9,450	9,450	9,450	9,450
Fixed O&M Cost/kW/Year	10.62	27.7	10.11	10.32	10.32	11.35	31.50	31.50
Insurance as Percent of Capial Cost	0.05%	0.00%	0.05%	0.05%	0.05%	0.00%	0.00%	0.00%
Property Tax as Perent of Capital Cost	0.50%	1.00%	0.50%	0.50%	0.50%	0.00%	0.00%	0.00%
Variable O&M Cost/MWH	2.23	1.70	2.23	2.28	2.28	2.28	4.00	4.00
Fuel Price/MMBTU in 2006	1.21	1.21	1.21	1.24	1.42	1.42	1.42	1.42
Capacity Factor	88%	88%	88%	88%	88%	88%	88%	88%
O&M Inflation	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Fuel Cost Inflation	2.00%	2.00%	2.00%	2.00%	2.50%	2.50%	2.50%	2.50%
Tax Rate	40%	40%	40%	40%	43%	43%	43%	43%
Fixed Property tax and Insurance	0.00	0.00	0.00	0.00	0.00	24,592	24,592	24,592
Working Capital as Percent of Debt	0%	0%	0%	0%	0%	5%	5%	5%
Debt Financing Fees as Percent of Project Cost	1.5%	1.5%	1.5%	1.5%	1.5%	2%	2%	2%
O&M Initial Escalation Factor for 2011 Costs	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16
Fuel Cost Initial Escalation Factor for 2011 Costs	1.10	1.10	1.10	1.10	1.00	1.00	1.00	1.00
Initial Capacity Factor	88%	88%	88%	80%	80%	80%	80%	80%
Construction Profile	1	1	1	1	2	2	2	2

Q How do modifications of the Big Stone analysis to reflect comparable tax and inflation assumptions, project financing, a first unit site and internalized costs affect the comparison between Mesaba and Big Stone?

A In comparing the adjusted Big Stone to the Mesaba costs, I show the average nominal price, the average real price and the levelized real price. Since the cost is modeled to be representative of risks that would occur with a PPA, I use the same discount rate for both alternatives in levelizing the ratepayer cost. I compare the Big Stone cost to the Mesaba cost that is adjusted to remove the effect of natural gas energy. The corrected analysis is shown in the table below:

Summary of Corrected Mesaba versus Big Stone Analysis

	Cost/MWH with Emissions			
	Levelized Nominal	Average Nominal	Levelized Real 2006 $	Average Real 2006 $
Mesaba: Dr. Amit Original Analysis	94.47	100.88	65.19	63.85
Big Stone: Dr. Amit Before Increase	59.17	63.29	41.10	40.29
Big Stone: Use of PA Update	82.93	88.69	57.59	56.47
Big Stone: Adjustment to Reflect Capital Cost Increase	73.75	78.88	51.22	50.22
Big Stone: Adjustment to Reflect Starting Point	76.21	76.21	52.92	51.89
Big Stone: Adjustment for Common Inflation, Taxes and Fuel	80.12	85.69	55.64	54.56
Big Stone: Adjustment for Internalized Costs	199.41	90.74	58.92	57.77
Big Stone: Adjustment for Existing Utility Plant Site	96.31	103.01	66.89	65.58
Big Stone: Flour Assumptions	98.97	105.85	68.73	67.39
Percentage Big Stone Above Mesaba After Adjustments but ***BEFORE risk benefits, environmental, economic development and real options to switch fuel***	4.76%	4.92%	5.43%	5.54%

Q What costs are not reflected in this analysis?

A The analysis still has very different risks to ratepayers in the Mesaba case relative to the Big Stone case. Therefore, one would expect all things being equal, that the Mesaba PPA would have a higher cash cost, and even then it would represent a better risk-adjusted cost. The reason the Mesaba PPA has lower cost before considering risk, real option, environmental or economic development benefits is because of the efficient manner in which the plant has obtained financing. These efficiencies include guaranteed debt at a low cost, investment

tax credit and high debt financing. While the cost of capital is efficient it is still driven by debt constraints.

VII. COMPARISON OF MESABA PLANT WITH NSP BROWN FIELD SITES

Q How have you evaluated the comparison that Dr. Amit made with the future Sherco 4 and the proposed Comanche Peak coal plants?

A At the time of writing this testimony we have been unable to obtain the underlying cost and operating assumptions the lie behind the cost per MWH numbers for Comanche Peak and the Sherco 4 coal plants. Given the lack of transparent data, I have researched information published by Xcel Energy in their least cost planning documents. This analysis demonstrates that the comparisons Dr. Amit makes with Xcel Energy numbers are not valid because:

- In the case of Comanche Peak, the annual cost per MWH numbers do not come close to providing the company with its required rate of return when the cost forecasts and assumptions provided to Dr. Amit are evaluated against the published cost of Comanche Peak. Given such a fundamental inconsistency with the Xcel data (which is not due to any computational errors by Dr. Amit) no weight at all can be given to the Comanche Peak analysis.

- In the case of the Sherco 4 unit, the Xcel Energy numbers appear to be derived from generic analysis taken from plant costs that are published by the EIA. These numbers do not reflect the increased recent costs of plants, the costs of building in Minnesota, risk allocation, and the other cost input deficiencies discussed above for the Big Stone plant. Correction of the generic numbers to

reflect risk allocation demonstrates that the Mesaba project is a least cost resource.

Q **How does Dr. Amit describe the NSP plants that he uses as a basis for comparison with Mesaba?**

A Dr. Amits describes the basis for comparing these two Xcel coal plants with the Mesaba plant as follows:

> I have analyzed two additional alternatives. The first of the two additional alternatives is an Xcel plant in Colorado that has been approved and is beginning construction. The plant, Comanche Unit 3, is a 750 MW base load supercritical coal plant. The proposed service date for the plant is October 2009. The plant will be constructed on a brown field which has two existing coal plants, Comanche Units 1 and 2. The second additional alternative is a 750 MW supercritical coal plant that may be built in Becker, Minnesota by Xcel. The plant, Sherco 4, would be built on a brown field with existing coal plants. Xcel to date has made no public announcement regarding a proposed Sherco Unit 4. (Amit testimony at page 25)

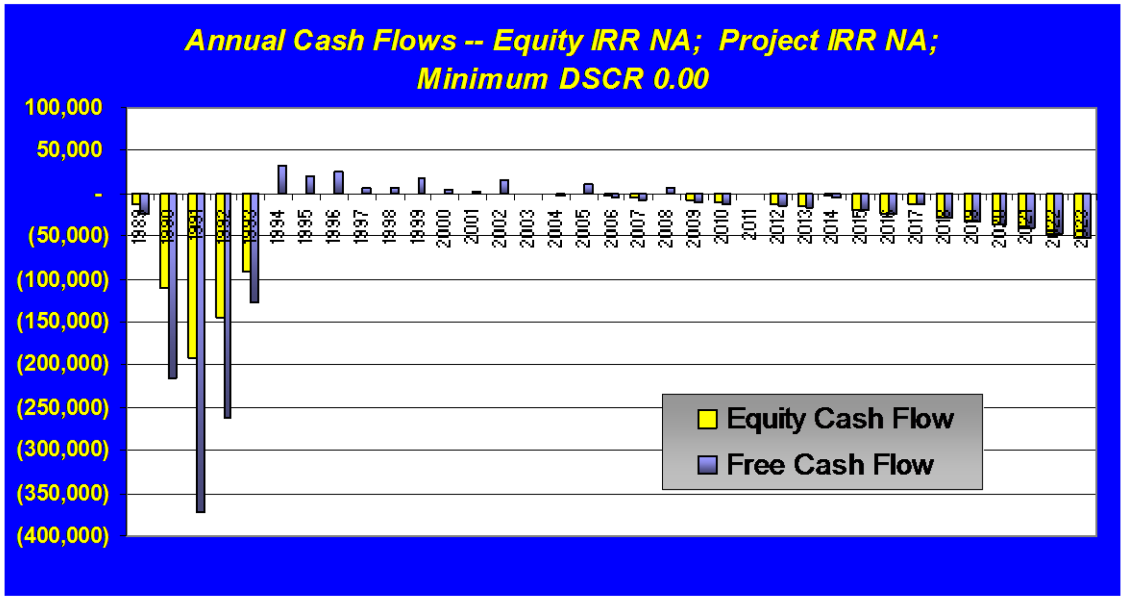
The source of Dr. Amit's information on the Sherco plant is from a data request from NSP as demonstrated by the following statement in his testimony:

> In response to the Department's Information Request No. 105, Xcel provided the estimated annual cost and annual produced energy, assuming an 80 percent capacity factor. The information is provided for

> the period 2015 through 2044. To compare the same periods, I projected the annual prices for the period 2011 through 2014, by using an annual deflation factor of 1.09 percent. (Amit testimony at page 28)

Q Is the estimated capital cost of Comanche Peak Unit 3 consistent with the cost/MWH numbers provided by Xcel?

A **No.** A 2004 Xcel Energy press release quotes the cost of Comanche Peak at $1,800 per kW. This cost includes scrubbing equipment at the other Comanche Peak units. I have entered this plant cost as well as the revenue per MWH from Dr. Amit's EA-6 in a financial model similar to that used in the Big Stone analysis described above. I used O&M cost, fuel cost and financial data from the Big Stone analysis along with the 80% capacity factor assumption quoted above. Unlike the Big Stone model, the benchmarking process did not come anywhere near to providing a reasonable returns to investors. Instead, the analysis demonstrates that, if the prices quoted were valid, then the Comanche Peak plant would not have sufficient cash flows to provide any return to investors as shown in the graph below. This casts very serious doubt on the Comanche Peak cost per MWH numbers presented in Dr. Amit's analysis. The cash flows produced from the cost/MWH numbers combined with operating cost assumptions produce results as shown on the graph below:



Q Turning to the assumptions for Sherco 4, have you researched how Xcel Energy generally makes assumptions with respect to generic new generating plants in its resource planning?

A Yes. In its 2004 least cost planning documents, NSP made the following statement with respect to assumptions for new resources:

> ***We relied on estimates contained in the Department of Energy's Energy Information Administration ("EIA") "Annual Energy Outlook" for … resource inputs, with certain adjustments.***
>
> The adjustments included:
>
> • We increased pulverized coal capital costs by approximately 15.5% to reflect the additional construction cost of emissions controls that are likely to be required to permit a new coal facility in Minnesota. The EIA based its capital cost estimates on a coal plant with a baghouse and SO2 scrubber….

- We increased the Pulverized Coal heat rate estimate by approximately 12% to reflect additional information obtained from other industry sources including EPRI TAG and the Company's recent bidding process.

In the Colorado 2004 least cost plan, Xcel Energy made the following statements.

> The EIA capital cost estimate for a 600 MW pulverized coal facility was increased from $1,212/kw to $1,400/kw to reflect the construction cost associated with a pulverized coal unit with emission controls that the Company believes would be needed to permit a new coal facility in Colorado. The EIA capital cost estimates were based on a coal plant with a baghouse and SO2 scrubber. PSCo elected to use a $1,400/kw capital cost to represent a new plant with a baghouse, SO2 scrubber, selective catalytic reduction ("SCR") for NOx, and activated carbon injection (or other mercury control agent) for mercury control. This adjustment advantaged wind and gas-fired technologies within the analysis.
>
> Pulverized Coal Heat Rate
>
> For purposes of the screening analysis, the EIA heat rate estimate for a 600 MW pulverized coal facility was increased from 8,500 btu/kwh to 9,500 btu/kwh to reflect what the Company believes to be a more realistic estimate. This adjustment advantaged wind and gas-fired technologies within the analysis.
>
> Use of Generic Resource Representations

The generation technology cost and performance representations used in this analysis are not based on actual estimates to construct such facilities in Colorado at specific locations. Instead they are what are commonly referred to as "generic" estimates, meaning that they represent expected costs and performance of major equipment items involved with construction and operation of these types of generating facilities. Actual detailed engineering cost and performance estimates for a specific generating facility will include a host of factors specific to the site under consideration (e.g., permitting requirements, land, water, transmission, fuel, etc.) that can add or reduce costs and performance from what is estimated for the "generic" facilities. What is important in comparing technologies within a screening analysis such as this is accurately representing the relative cost and performance differences between the technologies being considered.

The approach used by PSCo was to collect the fundamental cost and performance information from a single industry source. In doing so, PSCo believes that one is more apt to get estimates that are based on a common set of assumptions and thus better maintain the relative relationships between technologies than if a different industry source was used to represent each of the technologies considered.

Q Comment on Xcel Energy's statement that it uses EIA data so that different technologies are compared using a common set of assumptions so as to maintain relative relationships?

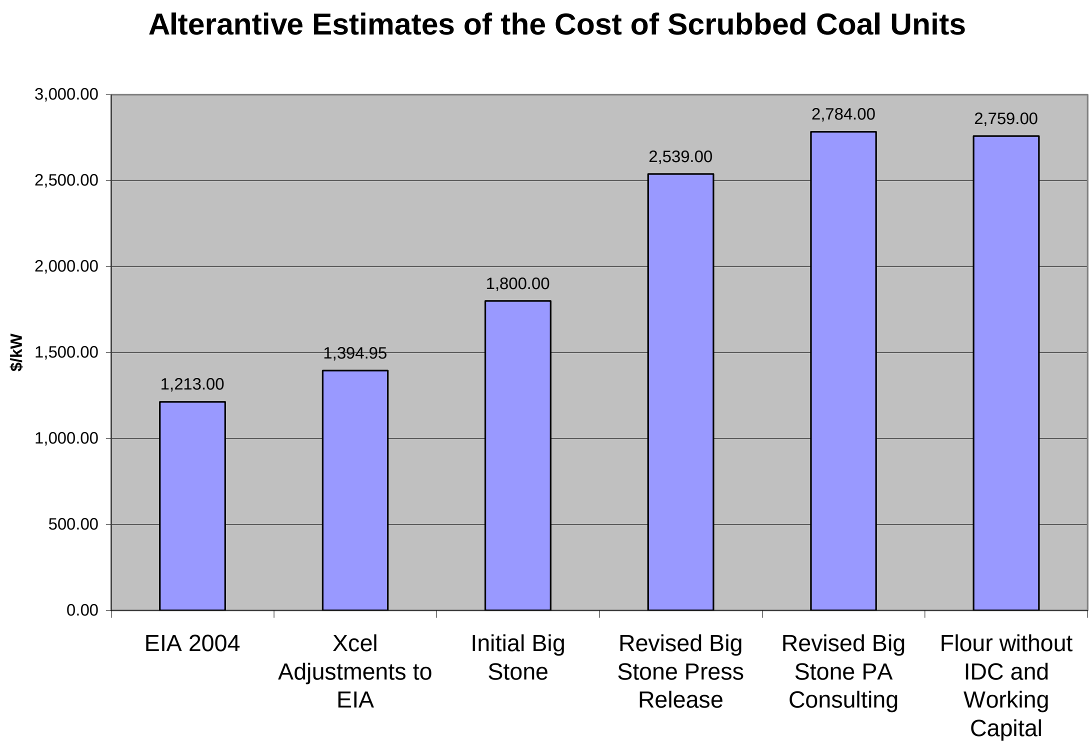
A While maintenance of relative relationships is a commendable objective, abstract numbers from published data does not serve as a firm foundation for making resource comparisons to concrete proposals before the Commission. In addition, the Fluor analysis provides a bottom up, Minnesota site-specific estimate that is current and uses methodology that is consistent with the cost analysis of the Mesaba plant

Q What are cost numbers for coal units published by the EIA?

A The numbers are dramatically below the current cost estimate of Big Stone, the Comanche Peak estimate and the analysis developed by Fluor. The EIA numbers used in the Annual Energy Outlook for 2004, 2005 and 2006 are summarized in the tables below.

Information on New Coal Plants Published by EIA

EIA Plant	Online Year	Size MW	Leadtime Years	Base Cost $/kW	Contingency Factor	Total Overnight Cost ($/kW)	Var OM $/MWH	Fixed O&M $/kW	Heat Rate (BTU/kWh)	Heat Rate Nth of Kind
Scrubbed Coal 2004	2007	600	4	1091	1.07	1,168	3.10	24.81	9000	8600
Scrubbed Coal 2005	2008	600	4	1134	1.07	1,213	4.06	24.36	8844	8600
Scrubbed Coal 2006	2009	600	4	1167	1.07	1,249	4.18	25.07	8844	8600



Q How did you begin your analysis of the Sherco 4 numbers presented byDr. Amit?

A I began with the EIA numbers published in the 2005 EIA report. Next, I escalated the operating and maintenance costs to 2011 – the starting point of Dr. Amit's analysis. I escalated the plant cost which are stated on an overnight basis to the middle of the construction period – 2008. I then entered other parameters published by the EIA into the financial model describe above for the Big Stone

plant including the 12% increase in heat rate assumed by Xcel. The financial model computes interest during construction on the plant to convert the over night costs into actual nominal costs including financing.

When the adjusted EIA data are entered into the financial model along with the annual cost/MWH, the internal rate of return on equity is only 4.46%. This demonstrates—as was the case with the Comanche Peak—that the Xcel $/MWH numbers simply do not add up to an analysis of the nominal costs required to cover the all-in costs of a new plant in 2011. Since the Xcel numbers are not transparent—we do not have access to the particular financing assumptions nor the techniques used by Xcel to compute the numbers—there is not enough information to further explain the inconsistency. In contrast, I have provided all of the spreadsheets with formulas in tact as part of my work papers.

Q How did you correct the Xcel Sherco annual cost per MWH data to make it internally consistent?

A I have derived a set of prices that would allow the project to earn a 12% return on equity as in the Big Stone analysis discussed above. After entering the adjusted EIA data into the financial model along with prices that allow the project to earn 12%, the prices are 33% than the numbers provided by Xcel Energy to Dr. Amit. These numbers contain the same coal prices, escalation rates, interest rates, O&M inflation, property taxes and other items that are explained above as part of the Big Stone modeling.

Q What adjustments should be made to the generic EIA numbers to make them comparable to the Mesaba project?

A *I have adjusted the plant cost and the O&M cost so that the EIA information used by Xcel energy are put on an equal footing as the Mesaba plant in terms of timing and risk. These adjustments include:*

- *A 35% increase in plant costs to represent current run-up in construction costs*
- *A further 25% increase in the capital to represent paying for an EPC contract in which private developers rather than ratepayers incur construction cost over-run and delay risks*
- *A 10% increase in O&M to reflect costs incurred to lock-in operating expenses*
- *A 65% debt to capital ratio and a 1.4x debt service coverage ratio constraint to represent financial risks to accept plant availability and other risks accepted by investors*

Q **Discuss the recent increase in construction costs of generating facilities?**

A There is much discussion in this case and the Big Stone case with respect to construction cost increases to commodity price increases and demand pressures in the industry. Some of the cost increase data presented in the Big Stone case is shown on the table below. The table demonstrates that cost increases for generating options are projected to range from 35% to 87%.

	Big Stone	PA Consulting	
Supercritical PC			
Original	1,800	1,645	
Revised	2,539	2,461	
Increase	739	816	
Percent Increase	41%	50%	
	Missouri River Energy Services Presentation		
	Generation	Transmission	Total
IGCC			
Original	1,816	155	1,971
Revised	2,294	369	2,663
Increase	478	214	692
Percent Increase	26%	138%	35%
Simple Cycle			
Original	683	0	683
Revised	1,182	92	1,274
Increase	499	92	591
Percent Increase	73%		87%
NGCC			
Original	1,156	0	1,156
Revised	1,876	92	1,968
Increase	720	92	812
Percent Increase	62%		70%

The EIA data used by Xcel Energy clearly does not include the recent construction cost run-ups. This is highlighted by the fact that the EIA estimates for the 2006 Energy Outlook are less than 3% above the estimates in the 2005 Energy Outlook and the 2005 Energy Outlook numbers are only 3.9% above the 2004 Energy Outlook. *In modifying the EIA cost/kW numbers, so as to not be accused of overstating the case, I have increased the EIA over night capital cost estimates by 35%.*

Q ***What is the effect of increasing capital costs by 35% on the annual required cost per MWH that is required in order to earn a 12% internal rate of return on equity?***

A *I have derived the $/MWH amounts required $/MWH to cover the 35% increase in construction cost. The construction cost escalation increases the levelized cost by 17% above the prior scenario. As shown in the summary table at*

the end of this section, the increase in construction cost means that all-in nominal costs for the generic Sherco unit are within 1% of the Mesaba PPA prices. This analysis of a generic unit versus the Mesaba PPA must not stop at this point however, because it does not incorporate the difference in ratepayer risks that exist when a plant is financed with a PPA rather than generic utility financing.

Q Does the transfer of risks from ratepayers to investors affect the value of Mesaba versus a generic coal plant from a consumer perspective?

A It most certainly does. I have already described general issues associated with construction cost risk, availability risk and operation and maintenance cost risk above. The project finance model requires that all costs and risks be carefully identified, quantified, and contractually assigned. In the case of Mesaba, this approach has resulted in the lowest risk adjusted cost of power from the project. In teaching classes on project finance, I use case studies that demonstrate how investors have paid dearly when they have directly accepted those risks. In the classic project finance cases of Eurotunnel and Eurodisney, actual costs grew by a factor of 3 times over the original projection. The case of the Lake Road Power plant discussed above illustrates the importance of shifting technical risk away from the ratepayers.

Q How are risks allocated between ratepayers and Excelsior investors in the proposed PPA contract?

A Through setting various prices at fixed levels, including penalty provisions and allowing the pass-through of other items, some risks are allocated to investors

in the Mesaba plant and other risks are retained by ratepayers. Some of the risks that are allocated to investors rather than ratepayers include the following:

- Since the cost of the plant is fixed when EPC is signed, risks of construction cost over-runs over the construction period are allocated to investors. As is typical in such situations, the construction cost risk is allocated to construction contractors through a fixed price date certain turnkey contract.
- Since the amount of capacity that will be provided will be fixed at EPC signing, technological risk that the capacity of the plant will be less than the amount in the PPA is allocated to investors.
- Since the PPA defines a date at which the plant will begin to operate and no payments are made by ratepayers until operations commence, the principal risks of delays in construction and the associated carrying costs are incurred by Mesaba investors.
- Since the PPA includes penalties for not meeting availability requirements, investors incur availability risk and the ratepayers do not pay for the plant during hours it is not available.
- Since the PPA includes a severe reduction in the capacity payment for each hour the plant is not fully available on coal-derived syngas, investors incur risks associated with the gasifier and associated facilities not working as planned.

- Since the PPA fixes the value of the capacity payment in nominal terms, risks of changes in the nominal cost of capital are incurred by investors.
- Since the PPA contract is with NSP rather than directly with ratepayers, investors take the risk that NSP will not meet the contract provisions in the case of bankruptcy.

Q How have you quantified the effect of construction risks that are borne by contractors or developers instead of ratepayers in the Mesaba PPA?

A A general rule of thumb in project financing is that contacts with fixed prices and certain completion dates should earn a premium of 20% to 30% relative to projects involving cost plus contracts. Further, the premiums tend to be higher if the projects do not have conventional technology and if construction lead times are greater. Elements of construction risk that tend to push the premium up for a new coal plant are discussed in following quote from the Fluor report:

> The first SCPC plants in the United States were constructed in the 1950s. No new units have been placed in service in the United States since the mid 1980s. Newer units constructed outside of the United States since 1985 have incorporated advanced design features aimed at mitigating the operating and reliability problems experienced by earlier plants. New materials allow SCPC plants to operate at even higher pressures and temperatures, which further improves heat rates.

> In order to be permitted in Minnesota, it is anticipated that a SCPC plant would require, at a minimum, a full suite of advanced environmental controls including wet scrubbers, selective catalytic reduction, and mercury removal. It should be noted that there are no large supercritical units operating on PRB coal fuel with this full range of control technologies.

In allocating the construction cost over-run risk after the tariff is fixed at financial closing, technology risk and a substantial portion of delay risk away from ratepayers, private developers or contractors would earn a 25% cost premium. This premium would increase the relative, comparative over night capital cost of the coal plant to $2,730/kW and in turn raises the annual cost/MWH required to generate a 12% internal rate of return by 13% and implies that the risk-adjusted cost of energy from the generic utility SCPC unit is about 10% more expensive than the Mesaba PPA.

Q How have you quantified the effect of operation and maintenance risks borne by private investors instead of ratepayers in the Mesaba PPA?

A In a similar manner to the construction cost issues, the manner in which contracts are negotiated to fix operation and maintenance expense can be used to define the value of risk allocation away from customers. I have assumed that operations contractors require and earn a premium of 10% to guarantee a fixed price rather than to enter into a cost plus arrangement. Incorporating the operating and maintenance risk in this manner adds another 1% to the relative risk-adjusted cost per MWH of the generic coal plant.

The table below summarizes the adjustments I have made to the operating data for the generic coal plant:

	Base EIA Costs	Recent Cost Escalation	EPC Contract	O&M Contract
Capacity (MW)	600	600	600	600
Capital Cost ($/kW) without IDC	1,618	2,184	2,730	2,730
Heat Rate	9,905	9,905	9,905	9,905
Fixed O&M Cost/kW/Year	29.68	29.68	29.68	34.13
Variable O&M Cost/MWH	4.95	4.95	4.95	4.95
Fuel Price/MMBTU in 2006	1.42	1.42	1.42	1.42
Capacity Factor	80%	80%	80%	80%
O&M Inflation after 2011	2.50%	2.50%	2.50%	2.50%
Fuel Cost Inflation after 2011	2.50%	2.50%	2.50%	2.50%
Combined Income Tax Rate	43%	43%	43%	43%
Fixed Property tax and Insurance	24,592	24,592	24,592	24,592
Working Capital as Percent of Debt	5%	5%	5%	5%
Debt Financing Fees as Percent of Project Cost	2.0%	2.0%	2.0%	2.0%
O&M Initial Escalation Factor for 2011 Costs	1.00	1.00	1.00	1.00
Fuel Cost Initial Escalation Factor for 2011 Costs	1.00	1.00	1.00	1.00
Initial Capacity Factor	80%	80%	80%	80%

Q Are all of the risks that are allocated away from ratepayers incorporated in the above adjustments?

A No. Risks of penalties incurred for availability, problems with the gasifier or other technological issues, changes in the cost of capital and other items are not included in the analysis. To cover these risks, lenders in project finance require a debt service coverage ratio of above 1.0 using base case assumptions. To internalize the added risks that are incurred by financiers of a project I have applied more realistic financial assumptions than those used in the Big Stone analysis. These assumptions imply a real cost per MWH of $79/MWH which is 24% greater than the cost of the Mesaba PPA. [RENEE CAN THIS STAY IN?]

Summary of Corrected Mesaba versus Sherco Analysis

	Cost/MWH with Emissions			
	Levelized Nominal	Average Nominal	Levelized Real	Average Real
Mesaba: Dr. Amit Original Analysis	94.47	100.88	65.19	63.85
Sherco: Before any Adjustments	60.03	64.40	41.69	40.96
Sherco: Correction for Internal Inconsistency	80.05	85.88	55.60	54.62
Sherco: Correction for Recent Cost Escalation	92.74	99.49	64.41	63.28
Sherco: Correction for EPC Construction Contract	106.10	113.82	73.68	72.39
Sherco: Correction for O&M Risks	106.86	114.64	72.91	74.21
Sherco: Correction for Other Risks	116.28	124.74	80.75	79.34
Percentage Sherco Above Mesaba after Adjustments	23.08%	23.65%	23.87%	24.25%

XI. REAL OPTIONS THAT ACCRUE TO RATEPAYERS FROM THE MESABA PLANT AND ARE NOT AVAILABLE FROM OTHER ALTERNATIVES

Q What are real options in capital budgeting and investment analysis?

A Real options allow the manager of an asset to make different decisions in managing an asset depending on market forces or the variation in states of the world that are outside of its direct control. Classic examples of real options include the option to delay construction of a plant, the option to retire a plant, the option to expand a plant, the option to cancel a research program and the option to dispatch a plant.

Q Are real options valuable?

A Yes. It is now well accepted in financial economics that real options can be very valuable because they can limit the downside risk associated with market conditions such as changes in the price of a product that cannot be foreseen with certainty. For example, the option to expand a plant depends on whether market conditions warrant an expansion. If market is depressed and expansion is not justified, management does not have to expand the plant and the downside is limited. On the other hand if market conditions suggest that a plant should be expanded (because, for example, prices are high), the upside potential still exists. This example demonstrates that the added value of a real option depends on the volatility of future market conditions and the length of the lives of assets. If there is no volatility, there is no downside risk to protect against. If, on the other hand,

the market is very volatile, real options allow the manager to take advantage of the upside without being exposed to the downside.

Q Are there real options associated with the Mesaba project that do not exist with alternative scrubbed coal plants?

A Yes. The Mesaba includes at least four real options that do not exist for the SCPC plants that Dr. Amit used in his analysis of the value of the plant to ratepayers. These real options include the option to use petroleum coke, the option to take fuel from multiple different regions, the option to burn natural gas when the gasifier is not available and most importantly, the option to sequester carbon. The value of all of these real options accrues directly to ratepayers.

Q Describe the option to use petroleum coke instead of other coal?

A The Mesaba plant can either use up to 50% petroleum coke or 100% powder river basin ("PRB") coal. This means that the difference between the price of petroleum coke and PRB coal makes it beneficial to use more petroleum coke, it can use more of that fuel. On the other hand, if the basis differential goes the other way, the plant can use more PRB coal. Since the benefit of the fuel flexibility shows up in the energy charge, the benefit of the option to use petroleum coke accrues to ratepayers. Big Stone II, Comanche Peak 3 and Sherco 4 do not include a similar real option to use petroleum coke.

Q Describe the option to use alternative types of coal at Mesaba?

A Due to its proximity to alternative rail routes, the Mesaba plant has access to coal that is mined in different regions of the country. This option limits the exposure of ratepayers to regional spikes in the price of coal. An example of how

this option can protect ratepayers is the recent price spike in western PRB coal. Prices spiked more for PRB coal than for eastern coal. Without the option to use coal from alternative regions, a plant has no recourse but to accept the consequence of the price spikes. However, with flexibility to use eastern or western coal, the effect of price spikes in one region is limited. As with the case of the option to use petroleum coke, this option accrues to ratepayers through the energy charge in the PPA.

Q Describe the option to burn natural gas at Mesaba?

A Dr. Amit has pointed out that ratepayers are exposed to the risk of the gasifiers not working correctly. While there is a risk that these problems can occur in early years of the plant operation, the risk to ratepayers is mitigated by the ability of the plant to operate on natural gas. This provides a built-in source of replacement capacity at a fraction of the price of what it could cost on the open market, which is not offered by a conventional coal plant.

Q What is the option to sequester carbon dioxide?

A Without doubt, one of the most important issues facing the electricity generating industry in coming years is the issue of global warming caused by production of carbon dioxide. It is possible that in the future, there will be such high costs attributed to production of carbon dioxide that it becomes beneficial to sequester the carbon dioxide. If this occurs, the Mesaba plant can sequester carbon dioxide on a far more efficient basis than alternative coal plants. This means that the Mesaba plant hedges ratepayer risk that carbon dioxide costs will be attributed in rates.

To illustrate the real option to sequester carbon, think about two future states of the world. In one state of the world, no added carbon dioxide cost is incurred by ratepayers. Here, the sequestration option has no value to ratepayers. However in a second state of the world, carbon dioxide must be sequestered. In this case, the value of Mesaba increases dramatically relative to alternative plants that Dr. Amit uses in his analysis. Assume that the cost of sequestering carbon is $10/MWH for and IGCC and $25/MWH for an alternative plant. If the probability of requiring carbon dioxide sequestration is 50%, the difference between Mesaba and alternative plants with carbon sequestration should be given a 50% weight while the base analysis without sequestration should also have a 50% weight. The tables below illustrates the value of the carbon sequestration option.

	Without Sequestration	With Sequestration	Probability of Sequestration	Expected Cost
IGCC	60	70	50%	65.00
SCPC	60	85	50%	72.50
IGCC Cost Advantage After Sequestation				11.54%

Probability of Sequestration	IGCC Advantage
0%	0.00%
10.0%	2.46%
20.0%	4.84%
30.0%	7.14%
40.0%	9.38%
50.0%	11.54%
60.0%	13.64%
70.0%	15.67%
80.0%	17.65%
90.0%	19.57%
100.0%	21.43%

Q Are the value of real options included in typical PVRR analysis or in resource planning analysis?

A No. Any discounted cash flow analysis is founded on the notion that the distribution of cash flows is symmetrically distributed in an upside scenario and a downside scenario. The real options mentioned above limit the ratepayer risk and result in a distribution of busbar costs that have is skewed. With real options the potential for costs to increase is moderated while the possibility for costs to go down is not affected. When the scenarios are developed in resource plans using PVRR, the value of mitigated risk is typically ignored.

Q How could adjustments be made in Dr. Amit's analysis to appropriately measure the value of real options?

A One would have first have to measure the statistical properties of market and technological parameters including price spikes, volatility and the likelihood of various events occurring. These events include the volatility and price spikes in the basis differential between petroleum coke and PRB coal price, the volatility in regional coal price difference, the probability of the gasifier not working correctly and most importantly, the probability distribution of carbon dioxide production costs being imposed on ratepayers. Once these statistical properties are established, a variety of models could be used to quantify the value to ratepayers.

Q Have you quantified how these real options affect the analysis made by Dr. Amit of Mesaba versus other coal plants?

A No. Unfortunately due to time constraints I have not been able to complete this analysis. However, it is clear to me that the options I discussed above do have a lot of value to ratepayers. Further, similar real options are not available to ratepayers who will pay for the Big Stone plant nor for Xcel ratepayers who will pay for expansion plants at the Comanche Peak or the Sherco sites.

XI. RISK ISSUES IN THE PPA

Q While you have gone to some length in showing ratepayer risks are lower for the Mesaba plant than alternative, doesn't Dr. Amit suggest that too many risks are allocated to ratepayers and not enough are allocated to investors in the Mesaba plant?

A Yes. For example, Dr. Amit would like investors in the Mesaba plant to accept even more risk than is allocated through the current PPA draft. For example, he testifies:

> In particular, if the Seller abandons the construction in the later years or abandons production, NSP will have to contract for a significant amount of replacement capacity and energy. Such replacement capacity and energy may be much more expensive than the PPA's proposed rates or alternative projects that could have been contracted for by NSP earlier. If such a default should occur, Section 11.6 of Article 11 sets a limitation on damages. In case of termination of the PPA the damages are limited to $125/kW times

the reference capacity. Using a reference capacity of 603 MW the damages are limited to $75,375,000. Based on annual generation of 4,767,000 MWh at a cost of $90/MWh, the annual value of the lost energy as a result of termination **is** $429,031,512. Assuming that as a result of termination of the contract, NSP's replacement capacity and energy will cost $15/MWh more than under the PPA, than the capped damages of $74,750,000 will compensate NSP for only about one year of operation (4,767,000 x $15 = $71,505,000). Based on these numbers and the ambiguity of the cure provisions the operational risks are unreasonably allocated to NSP's ratepayers rather than to Excelsior. (Amit testimony, page ___)

Discuss how it is very difficult to make things risk free. If more risks are allocated to Mesaba investors, there is added cost. [QUOTE KAREN HYDE]

Q Do you agree with Dr. Amit that provisions of the PPA contract relating to termination upon the default of Excelsior imposes undue risks on ratepayers?

A No. While Dr. Amit suggests that the default provisions impose risks on ratepayers, in fact the provisions protect ratepayers. Dr. Amit testifies:

Q Based on the provisions in the PPA, do you have any concerns that NSP's ratepayers may not be reasonably protected from the financial risks of the PPA?

A Yes, I have concerns because ratepayers are not reasonably protected. The Department is concerned with the financial risks associated with Seller's

dissolution or liquidation. If such events occur in the late construction period or in early years of production, NSP would have to find replacement energy and capacity that could be very costly due to the short replacement time available. The PPA specifies no financial instruments such as a letter of credit, an escrow account or any other similar instrument that could serve as a financial warranty. Therefore, the Department concludes that the PPA does not reasonably protect NSP's ratepayers from the financial risk of the PPA."

Q Do you agree with this assessment?

A No. In a utility owned scenario, the ratepayer has similar opportunities for outages, either due to late startup or outages; in these cases, the utilities must source more expensive power either form their own system resources, or from the market. If they IPP plant is down, they are left with exactly the same potential cost for replacement power, but the benefit that exists is that the IPP plant does not get paid. Under the contract; with a PPA, ratepayers do not pay for capacity that is not available to them. Contrast this with the utility owned plant, where the ratepayer is paying for a plat that is not performing, as well as the cost of replacement power. While Dr. Amit suggests that the default provisions impose risks on ratepayers, in fact the provisions protect ratepayers.

Q Is this the end of your testimony?

A Yes.